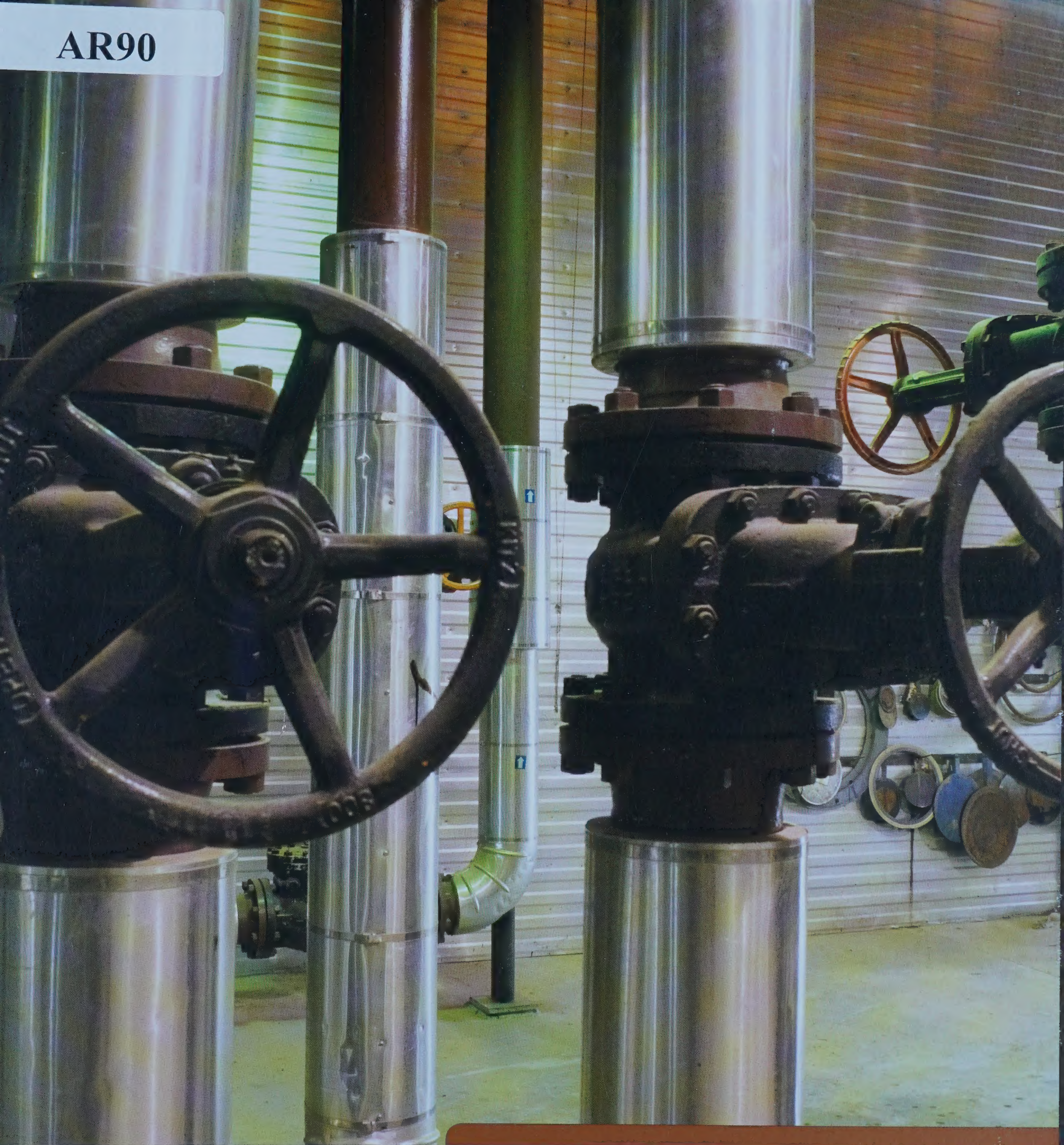


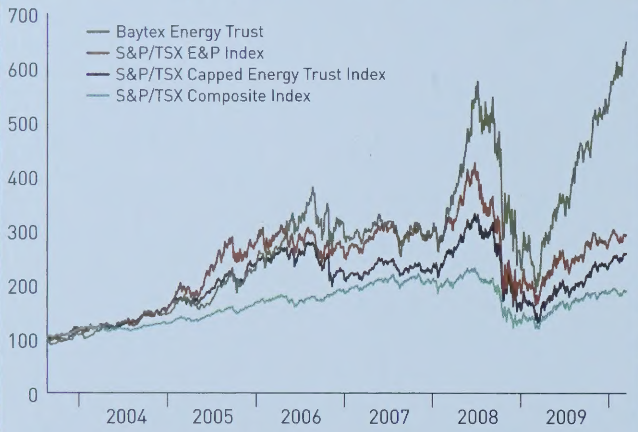
BAYTEX
ENERGY TRUST

Corporate Profile 2009

Contents

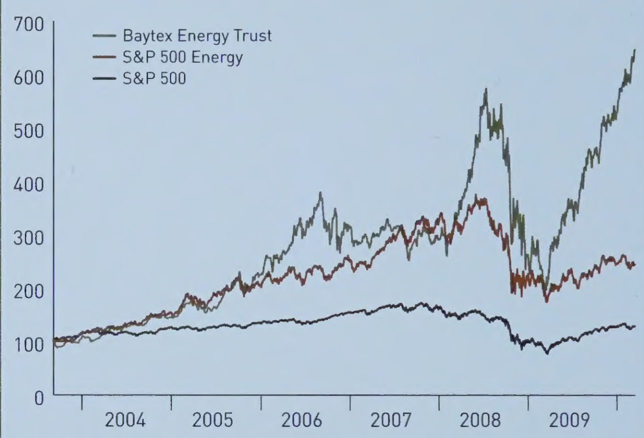
Baytex Energy Trust is a Calgary, Alberta based oil and gas trust engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. The trust also has an emerging presence in the United States. With changes to trust taxation laws in Canada set to take effect January 1, 2011, Baytex's current plan is to convert to a corporation, executing a growth-and-income model, by the end of 2010. Baytex is committed to maintaining its production and asset base through internal property development and delivering consistent returns to its unitholders. Trust units of Baytex are traded on the Toronto Stock Exchange under the symbol BTE.UN and on the New York Stock Exchange under the symbol BTE.

Baytex Total Return vs. Canadian Indices



Source: BMO Capital Markets, Bloomberg

Baytex Total Return vs. U.S. Indices



Source: BMO Capital Markets, Bloomberg

FINANCIAL ADVISORY: In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements contained in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: our plans to convert our legal structure from a trust to a corporation and the timing of such conversion; our average production rate for 2010; our reserves life index; our ability to grow our reserve base and add to production levels through exploration and development activities; petroleum and natural gas prices and differentials between light, medium and heavy oil prices; our cash payout ratio for 2010; our liquidity and financial capacity; our business model and dividend policy following our conversion to a corporation; our 2010 capital budget; our ability to fund our capital budget and cash distributions with funds from operations in 2010; drilling and operational plans for 2010; our Seal heavy oil resource play, including resource potential, our ability to improve production rates, recovery rates and capital efficiencies through enhanced completion techniques, finding and development costs, production efficiencies, our plans to install a commercial thermally-enhanced oil recovery project and the timing thereof, our assessment of the cyclic steam stimulation pilot project, steam-oil ratios, drilling and completion costs per well, initial production rates, estimated ultimate recoverable reserves and recovery factors; our Bakken/Three Forks, Viking and Pembina Cardium light oil resources plays, including resource potential, the number of potential drilling locations and initial production rates; our net asset value per trust unit (before income tax); the value of our undeveloped land holdings; and the amount of future asset retirement obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

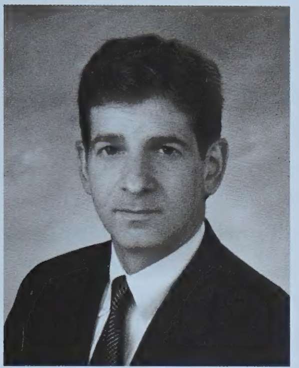
Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in petroleum and natural gas prices; variations in interest rates and foreign exchange rates; uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with our conversion to a corporate structure; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations, the timing of payment of distributions, if any; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; risks associated with residency restrictions in the ownership of our Trust Units; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the application of accounting policies; the activities of our operating entities and their key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonality; our permitted investments; risks associated with our structure and ownership of Trust Units; risks for United States and other non-resident unitholders and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Front cover: Baytex heavy oil battery at Celtic, in the Lloydminster area of Saskatchewan

All dollar amounts are in Canadian dollars unless otherwise denoted

Message to Unitholders



We are pleased to report our 2009 results to our unitholders. In 2009, we achieved record levels of production and reserves, as well as our second best year of funds from operations. Operationally, we continued to advance several key projects that should provide reliable and diversified growth in the coming years. We also recorded another year in which we replaced more than 100% of our annual production with reserves developed by our organic exploration and development ("E&D") investment activities. Finally, our balance sheet continued to improve, maintaining our financial position as one of the strongest in our sector. We were also fortunate to deliver the strongest total market return performance among our peer group in 2009. This market recognition leaves us honoured, and also determined to continue to focus on delivering sustainable income and growth to our unitholders.

OPERATIONS REVIEW

Production averaged 42,713 boe/d in the fourth quarter of 2009, and 41,382 boe/d for the full year, a 3% increase over 2008. With respect to product mix, Baytex is one of the most oil-weighted entities in the North American energy industry, with 80% of our production and 89% of our reserves represented by heavy and light oil.

Our 2009 capital expenditures ("CAPEX") were reduced from 2008 levels, in both aggregate terms and also for each of E&D and acquisition expenditures. Spending for E&D totaled $157 million, with the majority directed toward heavy oil projects. During the year, Baytex participated in the drilling of 113 gross (99.0 net) wells on our heavy oil, light oil and natural gas properties, generating a 96% success rate.

Our total capital program for 2009, including acquisitions, amounted to $290 million. This CAPEX program allowed Baytex to increase its reserve base in both proved and probable reserve categories for the sixth consecutive year, encompassing our entire history as an energy trust. At year-end 2009, our proved plus probable reserves, as evaluated by Sproule Associates Limited, reached 197 million boe. This reserve total represents a 12.4 year reserve life index at our expected production rate of 43,500 boe/d for 2010.

Baytex continued to record strong CAPEX efficiencies in 2009. Finding, development and acquisition ("FD&A") costs were $11.63/boe on a proved plus probable basis (excluding future development capital), resulting in a recycle ratio of 2.4. Our strong capital efficiency is further demonstrated by replacement of 113% of the year's production through E&D, while reinvesting only 47% of funds from operations ("FFO") into E&D activities. Including acquisitions, we replaced 165% of our 2009 production. These results are consistent with our long-term performance in capital efficiency. Our five-year average FD&A cost of $9.72/boe, recycle ratio of 2.8 and reserve replacement ratio of 214% all rank among the best in our industry.

At Seal in the Peace River oil sands region, we drilled 17 new cold horizontal producers, continuing our record of 100% drilling success and increasing production from this important growth property to 7,000 bbl/d by the end of 2009. We advanced our use of multi-lateral horizontal wells at Seal to increase production rates and recoveries, and to further improve our capital efficiencies. We continue to work toward installation of our first commercial thermally-enhanced oil recovery project at Seal, planned for late 2011.

Production increased from our Lloydminster core heavy oil area through new drilling, recompletion of existing wells and an asset acquisition. In the third quarter, we acquired predominantly heavy oil properties in Kerrobert at the southern end of the Lloydminster area. These properties, purchased for $86 million, currently produce approximately 2,800 boe/d. We have identified a number of opportunities to expand both cold production and steam assisted gravity drainage ("SAGD") operations on the acquired lands, and expect to invest in these opportunities over the next few years.

We continued to pursue several light oil growth projects of long-term importance. The Bakken-Three Forks play

in North Dakota and the Viking play in Alberta and Saskatchewan utilize horizontal wells, most often with multiple hydraulic fracture stimulations, to induce light oil production from low permeability reservoirs. These plays contain very large volumes of light oil resource in place and have the potential, over time, to generate significant increases in Baytex's light oil production and reserves. We assembled these new light oil resource plays with three objectives in mind: value accretion to our unitholders, enhancement of our overall growth rate and diversification of our long-term product and project mix. These light oil resource plays will complement the growth of our heavy oil projects at Seal and Lloydminster.

In the fourth quarter of 2009, we completed our deferred acquisition payments for the Bakken-Three Forks land that we added to our portfolio during 2008. We drilled and completed our first operated wells in this play, achieving a 100% success rate and recording initial production rates of approximately 300 bbl/d per well. Drilling activity will continue at an increased pace in 2010.

In our Viking play in Alberta, we drilled three successful multi-lateral horizontal wells (without hydraulic fracturing) with an average initial production rate in excess of 130 bbl/d per well. During 2010, we plan to continue with this type of development activity in the Viking in Alberta, as well as use single-lateral horizontal wells with multi-stage hydraulic fracturing in our Viking project in Saskatchewan.

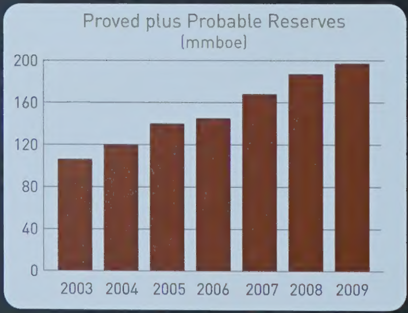
FINANCIAL REVIEW

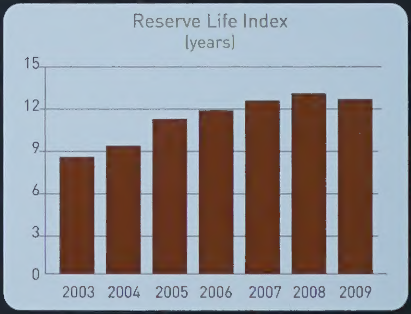
We are encouraged by our operating results and CAPEX efficiencies, and it is through these measures that we seek to differentiate ourselves from our competitors. Our success in these areas helped us post strong financial results despite significantly lower commodity prices as compared to 2008.

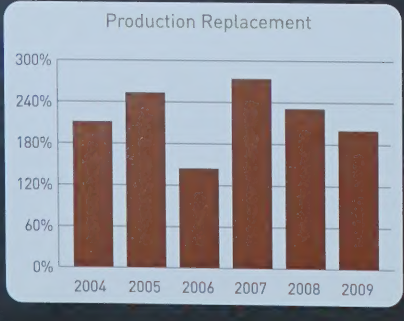
West Texas Intermediate ("WTI") oil price for 2009 averaged US$61.80/bbl, a decrease of 38% from the average for 2008. However, this average price does not fully illustrate the extraordinary volatility in oil prices over the course of 2009. As the economic crisis deepened and the world economy contracted, WTI bottomed at US$32.70/bbl in January 2009. With the easing of the systemic financial crisis and signs of economic recovery, WTI recovered to a peak of US$82.00/bbl in October 2009.

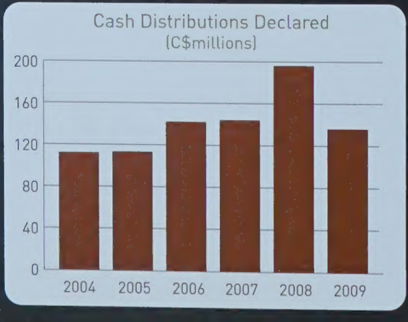
Because WTI prices are denominated in U.S. dollars, a strengthening Canadian currency partially reduced the positive impact of the oil price recovery for Canadian producers. The Canadian dollar, which began 2009 at US$0.82 following the worldwide flight to U.S. dollars during the initial stages of the financial crisis, rose to

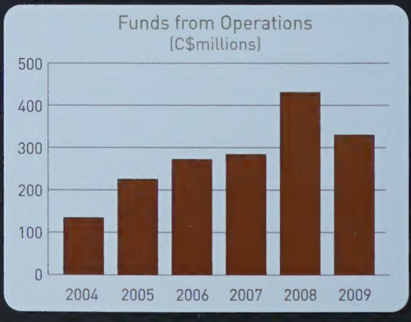
BAYTEX RECORD SINCE TRUST INCEPTION







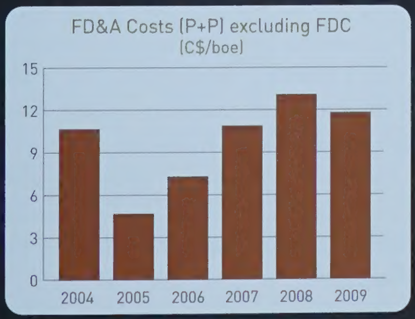


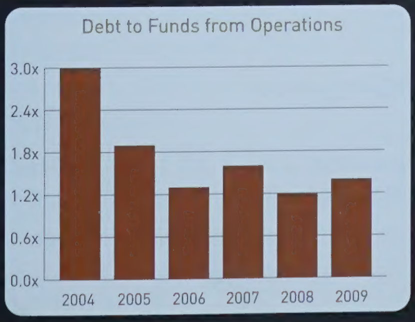


US$0.96 by the end of 2009. In late 2008, we were of the view that the Canadian currency was likely to strengthen versus the U.S. dollar, and put in place currency hedges to protect about 33% of our foreign exchange exposure for 2009, thereby reducing the impact of the stronger Canadian dollar on our 2009 cash flow.

We are fortunate to be particularly weighted to heavy oil, which has benefitted from a narrowing of differentials and reduced volatility as compared to WTI. The heavy blend benchmark, Western Canadian Select ("WCS"), sold at a 16% discount to WTI during 2009 as compared to a 22% discount during 2008. In the first quarter of 2010, differentials for WCS are averaging approximately 12% of the WTI price, resulting in wellhead prices for heavy oil that are yielding very high rates of return on our investment program. The improvement in heavy oil differentials is the result of a number of North American and global supply/demand factors: increased demand from refineries in both North America and Asia that have been reconfigured to process more heavy oil, reduced output of heavy oil by traditional suppliers such as Mexico, and increased pipeline capacity to U.S. markets.

Natural gas prices followed a similar, albeit less pronounced, trajectory as crude oil. After beginning 2009 at $5.79/mcf and bottoming at $2.76/mcf in August, AECO spot prices recovered to $5.51/mcf by the end of the year due to a relatively cold and early winter in much of North America. With only 14% of revenue coming from natural gas in 2009, the fluctuations in natural gas prices had a minor impact on our cash flow.





Operating expenses decreased as costs for fuel and oilfield services declined due to the recession and the commodity price retracement. For 2009, our operating expense averaged $10.83/boe, a 7% decrease from the previous year. Transportation expense increased by 14% to $3.22/boe due to higher production from Seal, which requires long-haul trucking. Exclusive of non-recurring compensation expense related to U.S. tax treatment of our trust unit rights incentive plan, general and administrative expense ("G&A") expenses increased 5% to $2.09/boe. We do not capitalize any G&A costs, and our G&A expense has consistently been below sector averages.

FFO for 2009 was our second-best ever at $332 million, a decrease of 23% from 2008's record level which was generated during a period of much higher commodity prices. FFO increased each quarter during 2009, from a low of $59 million in the first quarter to a high of $97 million in the fourth quarter.

In response to the rapid descent of commodity prices in late 2008 and early 2009, we reduced our monthly distribution rate from $0.18 per unit to $0.12 per unit in February 2009 to adjust cash outflows to inflows and to preserve liquidity. As a result of the oil price recovery and our strong operating results, we restored the distribution level to $0.18 per unit in December 2009. Cash distributions for 2009 were $138 million, bringing our cumulative cash distributions to more than $1 billion since trust inception.

Our payout ratio for 2009 averaged 41%, net of participation in our distribution reinvestment program ("DRIP"). Importantly, we were able to fund 100% of our E&D CAPEX and cash distributions from FFO, which we consider a key measure of the sustainability of our growth-and-income model. At our current monthly distribution of $0.18 per unit, our cash payout ratio (net of DRIP) is forecast to be about 40% for 2010, based on the current commodity price strip.

Total monetary debt at year-end 2009 was $474 million. This debt level corresponds to 1.2 times annualized FFO for the fourth quarter of 2009. In August 2009, we placed a $150 million issue of 9.15% seven-year senior

unsecured debentures in the Canadian non-investment grade bond market, the first of its type by an energy issuer in this nascent debt market. Our notes issue was well-received, and with subsequent reductions in credit spreads, currently trades at approximately a 7% yield. In September 2009, we retired US$180 million of senior subordinated notes which were scheduled to mature in July 2010. Our new Canadian issue and our history as an issuer in the U.S. bond market illustrate our capability to access the debt markets should we have a need for external financing.

Most of our debt is represented by drawings on our reserve-based revolving credit facilities, which are provided by a syndicate of eight banks from Canada, the U.S. and Europe. At year-end 2009, our undrawn credit facilities were $198 million, providing us significant liquidity. We are also pleased to note that our banking syndicate increased our credit facilities by 6% at mid-year 2009, making us one of very few North American energy entities to receive an increase in banking facilities in a credit-constrained environment.

OUTLOOK

One year ago, we faced a deepening global recession, a commodity price collapse and a credit contraction all at the same time. Consequently, we took the prudent steps to maintain our sustainability by reducing our distribution and our 2009 CAPEX program from its originally-planned level. Although we made adjustments in response to the financial crisis, we also continued to focus on our long-term strategy to add real value to Baytex.

In this very capital-intensive business, we maintained our investment efficiency. We ensured operational sustainability by continuing to expand our heavy oil and light oil project inventory. We diversified our sources of capital with our Canadian debt offering. We increased our financial flexibility by achieving increased banking facilities in a difficult credit environment. Most importantly, we strengthened our organization in a number of key areas, including thermal operations, exploration, risk management, long-range planning, legal, financial reporting and investor relations.

The market rewarded Baytex with a sector-leading total return of 121% during 2009, including both appreciation of our unit price and reinvestment of distributions. Our total return since inception of the trust to the end of February 2010 has been 546%, significantly higher than the 157% return of the S&P/TSX Capped Energy Trust Index over the same period.

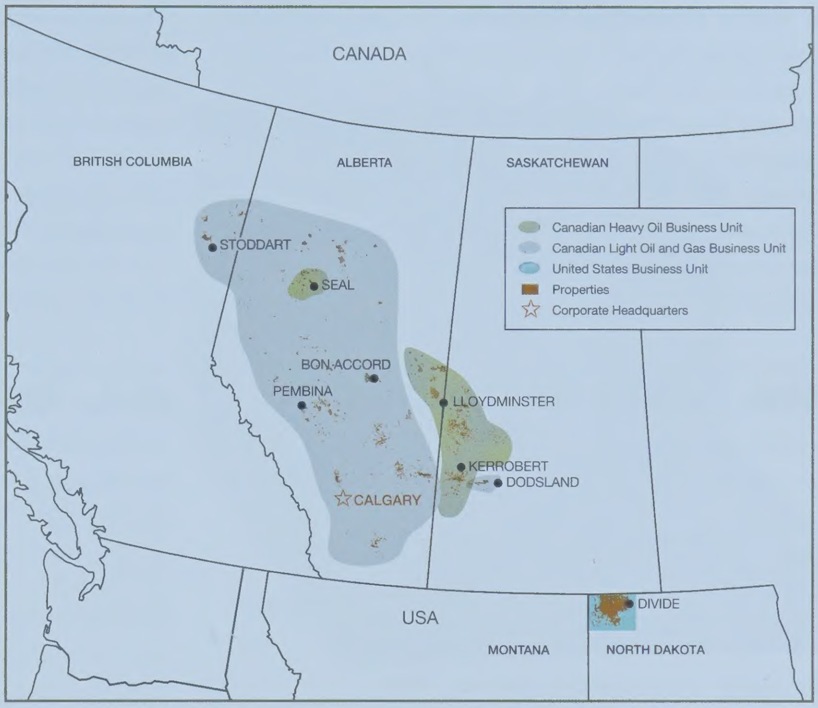
January 1, 2011 marks the implementation of the Tax Fairness Plan announced by the Canadian federal government in 2006. In 2010, we are transitioning to a growth-and-income model, presaging our planned conversion to a corporation prior to the beginning of 2011. Under the new corporate structure, we expect to maintain a significant dividend payout while placing more emphasis on growth than in the income trust era. Our planned 2010 capital budget of $235 million for E&D is designed to generate average production of 43,500 boe/d during 2010, a 5% increase over 2009. Based on the current commodity price strip, we are projecting that FFO in 2010 will be sufficient to fully fund our budgeted E&D CAPEX and cash distributions.

In the new corporate era, as in the trust era, we will base our business on sound technical decisions, prudent financial practices and the creation of real value from our assets. I would venture to say that the emphasis on capital efficiency that Baytex learned during the trust era should prepare us well for the coming corporate era. I can assure you that Baytex's management and staff, led by our Board of Directors, will continue to work hard on behalf of our unitholders as we make the transition to a corporation. It remains an honour to serve you, and we want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

Anthony Marino
President and Chief Executive Officer
March 15, 2010

Baytex Properties



Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Light Oil and Gas, and United States Business Units. Each Business Unit has an extensive portfolio of operated properties and development prospects. Within these Business Units, Baytex has established a total of eight geographically-organized teams, each with a full complement of technical professionals including engineers, geoscientists and landmen. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of these opportunities.

Canadian Heavy Oil Business Unit – The cornerstone of Baytex is our heavy oil operation. The Canadian Heavy Oil Business Unit accounts for more than 60% of current production and more than 70% of oil-equivalent reserves. Baytex's heavy oil operations consist primarily of cold primary production, but in some cases waterflooding and thermal operations are employed. Key properties include the Lloydminster region of west central Saskatchewan, Kerrobert in southwest Saskatchewan, which includes a Steam Assisted Gravity Drainage ("SAGD") project, and Seal in northwest Alberta, where Baytex has successfully tested Cyclical Steam Stimulation ("CSS") in addition to cold primary production. In 2009, production in the Canadian Heavy Oil Business Unit averaged approximately 25,900 boe/d (95% crude oil). We drilled 90 gross (82.3 net) wells in 2009 with a resulting success rate of 97%. Our net undeveloped land position totals 382,000 acres.

Canadian Light Oil & Gas Business Unit – Although Baytex is best known as a "heavy oil" company, we also possess a growing array of light oil and natural gas properties. The geographic scope of our Canadian light oil and gas operations spans Alberta, southwest Saskatchewan and northeast British Columbia. The Conventional Light Oil and Gas Business Unit accounts for approximately 33% of current production and about 20% of oil-equivalent reserves. Emerging light oil resource plays within our portfolio include the Viking at both Bon Accord in southeast Alberta and Dodsland in southwest Saskatchewan, as well as Cardium development at Pembina in central Alberta. During 2009, we drilled 16 gross (14.5 net) wells at a 94% success rate. Our net undeveloped land positions totals 289,000 net acres at year-end 2009.

United States Business Unit – We first acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. At year-end 2009, our net undeveloped acreage position totaled 126,000 acres. Our largest property in the United States Business Unit is our Bakken-Three Forks project in North Dakota. We also hold lands in several other U.S. states. In 2009, we participated in the drilling of 7 gross (2.2 net) wells for a success rate of 100%.

Focus on Seal

A Highly Prospective Property. No property better exemplifies Baytex's future growth potential than Seal, located in the Peace River oil sands area of northwest Alberta. Since the beginning of 2000, we have accumulated 105 sections of 100% working interest lands, grown production from zero to a current rate in excess of 7,000 bbl/d and at year-end 2009, our proved plus probable reserves totaled 55 mmboe. Production at Seal in 2009 averaged 5,100 bbl/d, up 38% versus a 2008 average production rate of 3,700 bbl/d. Through year-end 2009, we have drilled 61 oil wells with a 100% success rate. The estimated resource potential of our prospective lands at Seal is 50 million barrels of original oil in place ("OOIP") per section. The vast resource base, combined with the exceptional capital and production efficiencies Baytex has achieved, offers significant upside potential, making Seal one of our main areas of development focus going forward.

SEAL – OPERATING STATISTICS

Land position	105 sections
Average working interest	100%
Average production rate - 2009	5,100 bbl/d
2009 exit production rate	7,000 bbl/d
Proved plus probable reserves (YE 2009)	55 mmboe
Producer wells drilled to December 2009	61
Stratigraphic wells drilled to December 2009	26
Drilling success rate	100%

SEAL – RESERVOIR CHARACTERISTICS

Average pay thickness	15 - 20 metres
Average porosity	28%
Permeability	0.5 – 5.0 darcies
Depth	600 - 700 metres
Oil quality	11 °API

BAYTEX SEAL TIMELINE

2001 - 2004

- Acquired 96 sections of 100% owned and operated land
- Completed geological and geophysical work and identified drilling locations
- Drilled nine stratigraphic test wells

2005

- Added additional lands at Seal
- Drilled four stratigraphic test wells and six horizontal producing wells
- Production averaged 500 bbl/d; booked 4 mmbbl of proved plus probable reserves

2006

- Drilled three stratigraphic test wells and two horizontal producing wells
- Initiated reservoir simulation study of enhanced oil recovery potential
- Production averaged 550 bbl/d; booked 13 mmbbl of proved plus probable reserves

Stratigraphic test wells at Seal are expendable vertical wells drilled to a depth of about 600 meters to acquire full-section cores of the Bluesky oil sand. We measure the permeability of the formation and the viscosity of the oil it contains over the cored interval. These measurements indicate whether the Bluesky oil sand is amenable to cold production, thermal production, or both methods at the stratigraphic test well location

Technology Continues to Evolve. The technology we employ at Seal continues to evolve, leading to greater production rates, increased recovery, and even stronger capital efficiencies. Our initial completion technique involved drilling mile-long single leg horizontal wells at a depth of approximately 600 metres. These wells initially produced at rates of between 150-200 bbl/d. In August 2007, we drilled our first multi-lateral well (dual-leg), and in February 2008, we drilled our first triple-lateral well. The completion technique continued to evolve throughout 2009 as we drilled one single-lateral, one dual-lateral, seven triple-lateral wells, three four-lateral wells, two six-lateral wells, and three eight-lateral wells. We are now achieving initial production rates on our eight-lateral wells in excess of 500 bbl/d. The figure opposite illustrates a typical eight-lateral well at Seal. And while it is still early in our overall Seal development, we remain excited for the long-term prospects the region offers Baytex. Importantly, our capital efficiency ratios remain strong with finding & development costs of under $5.00 per boe, and production efficiencies of under $5,000 per boe/d. In 2010, we expect to drill approximately 20 horizontal wells, largely comprised of multi-lateral wells.

EIGHT-LATERAL WELL AT SEAL

2007

- Drilled 17 new horizontal producing wells bringing the total number of producing wells to 25
- In August 2007, Baytex drilled its first multi-lateral well (dual-leg)
- Four new stratigraphic test wells drilled to identify extensions to the initial development area
- Production averaged 1,600 bbl/d; booked 28.7 mmbbl of proved plus probable reserves

2008

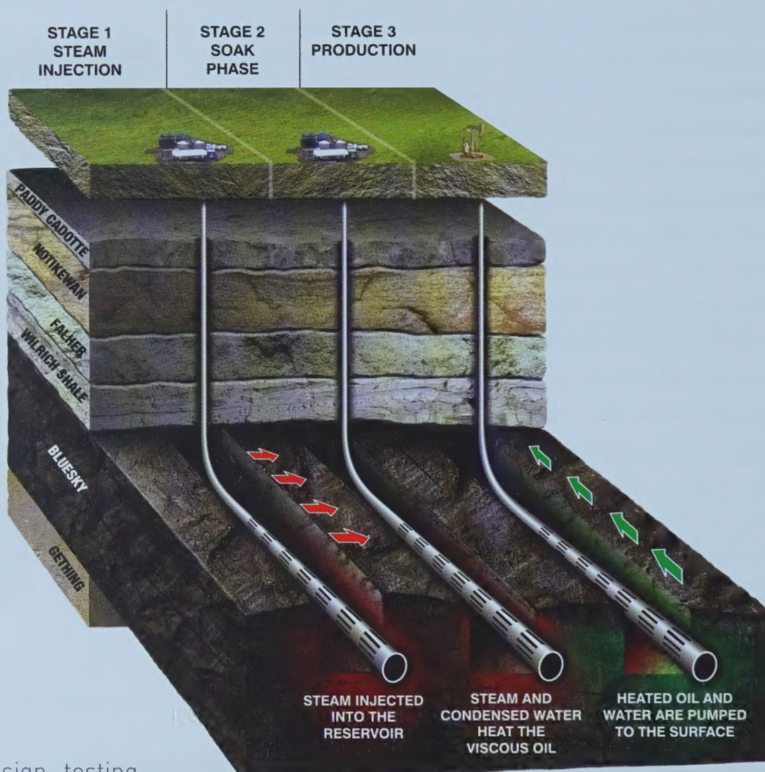
- Drilled 17 new horizontal production wells bringing the total number of producing wells to 44
- In February 2008, Baytex drilled its first triple-lateral well
- Cyclic steam pilot project carried out on an existing horizontal producer to validate the numerical reservoir simulation model
- The 2008 reserve report included the first assignment for thermal reserves at Seal
- Production averaged 3,707 bbl/d; proved plus probable reserves at Seal total 39.2 mmbbl

2009

- Drilled 17 new horizontal wells bringing the total number of wells drilled to 61, of which 59 were producing at year-end 2009
- Drilling technology continues to advance; Baytex drilled its first four-lateral, six-lateral, and eight-lateral wells
- The 2008 cyclic steam pilot project exceeds expectations; the test generated an impressive steam-oil ratio of 1.3 barrels of steam per barrel of oil
- Development plans continue for a 10-well commercial thermal project with targeted start-up of late 2011
- Production averaged 5,100 bbl/d; proved plus probable reserves at Seal total 55 mmbbl

The Next Step – Thermal Development. Under primary development, the recovery factor at Seal is estimated to be between 5% to 7% of original oil in place. Under thermal development, the recovery factor at Seal could potentially increase to 30%. In 2008, Baytex reached a significant milestone that we believe will prove important for our long-term growth. We successfully tested the application of CSS in a well that had previously been a cold producer. The results of the test significantly exceeded our expectations, with initial rates following steam injection exceeding 900 bbl/d. More importantly, the test generated an impressive incremental steam-oil ratio ("SOR") of 1.3 barrels of steam per barrel of incremental oil. This SOR is far lower than the average for projects in Western Canada, and suggests very high thermal efficiences and the potential for strong thermal operating economics. Based on our successful pilot, we are conducting the remaining design, testing and reservoir modeling activities to install a permanent steam project, with start-up targeted for late 2011. The figure above illustrates how a CSS project would work at Seal. In CSS, the same well is used for both steam injection and oil production. CSS is a lower cost form of thermally-enhanced oil recovery as compared to SAGD.

CYCLICAL STEAM STIMULATION AT SEAL



SEAL – PRIMARY DEVELOPMENT*

Cost per well (drill, complete, tie-in):	
Triple-lateral	$1.5 million
Eight-lateral	$2.0 million
Initial production rate per well:	
Triple-lateral	300 bbl/d
Eight-lateral	500+ bbl/d
EUR per well: Triple-lateral	405 mboe
Recovery factor	5% - 7% of OOIP

SEAL – THERMAL DEVELOPMENT*

Modular development – 10 wells per phase
Phase I targeted for initial production by year-end 2011

Capital requirement per phase	~$31 million
Anticipated production rate per phase:	
Peak year	1,700 bbl/d
Peak month	2,200 bbl/d
EUR per 10-well phase	3.8 mmbbl

Recovery factor – approximately 30% based on numerical reservoir simulation.

*Baytex internal estimates

Emerging Light Oil Plays

More than Just Heavy Oil. Baytex has a reputation of being a heavy oil company. It is a reputation we deserve, and one of which we are quite proud. Nevertheless, we have steadily assembled an enviable suite of light oil projects – two such projects are the Bakken-Three Forks play in North Dakota and the Viking play in southwest Saskatchewan and southeast Alberta. In addition, we have a smaller presence in the Pembina Cardium trend. To develop these resource plays, we will generally utilize horizontal wells with multiple hydraulic fracture stimulations to induce light oil production from these low permeability reservoirs. The plays contain very large volumes of light oil resource in place and have the potential, over time, to generate significant increases in Baytex's light oil production and reserves.

We put these new light oil resource plays in place with three purposes in mind: value accretion to our unitholders, enhancement of our overall growth rate and maintaining diversification of our long-term product mix and project mix. The light oil resource plays will complement development of our heavy oil assets, such as our resource play at Seal.

Williston Basin – Bakken-Three Forks Project. This light oil resource play is located mainly in the Divide County of North Dakota. Baytex first acquired an interest in the play in 2008, and today has an average 38% working interest in 96,000 net acres of land, of which over 90% is undeveloped. In 2009, we drilled four gross (1.5 net) operated wells with a 100% success rate. Initial production rates from our first three operated wells averaged 300 bbl/d, exceeding our previous model for this play by about one-third. For 2010, we will see drilling activity accelerated with approximately 15-20 gross (5.6–7.5 net) wells planned. Ultimately, we believe we have the potential to develop up to 150-300 gross wells in this project.

Viking Resource Play. During 2008, we developed a new resource play in the Viking sand at Dodsland in southwest Saskatchewan and in the Bon Accord area in southeast Alberta. The Viking zone is regionally charged with light oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex has targeted the less permeable but undeveloped areas of the play. In 2008, we drilled two successful horizontal producing wells, one each in Alberta and Saskatchewan. This was followed up in 2009 with another three gross (3.0 net) successful horizontal wells in Alberta with average initial production rates for the three wells in excess of 130 bbl/d per well. Our 2009 acquisition of heavy oil producing assets in the Kerrobert area included additional highly prospective Viking light oil lands. In aggregate, Baytex has amassed over 65,000 net acres of prospective Viking lands, 95% of which are located in southwest Saskatchewan. For 2010, we expect to drill up to 10 gross (9.3 net) Viking wells, split between Alberta and Saskatchewan. Ultimately, we believe this project could yield up to 260 net drilling locations.

Baytex pump jack at Bon Accord, in Southeast Alberta

Cardium Development. Baytex's position in the emerging Cardium play is located in the Pembina trend in west central Alberta. Baytex acquired its initial position in Pembina in June 2007 through a light oil asset acquisition and further expanded its presence in the area through the acquisition of Burmis Energy in June 2008. In the Cardium we have interests in approximately 10,000 gross acres of land. In 2009, Baytex drilled two gross (2.0 net) successful Cardium horizontal wells, which were completed with multi-stage fracture stimulations. We have identified the potential to drill up to 43 gross locations which will include up to five wells for 2010.

Reserves

Since our conversion to an oil and gas royalty trust in late 2003, Baytex has continued to demonstrate superior capital and operational efficiencies as we prudently execute our strategy for long-term sustainability. Our 2009 reserve report, as prepared by our independent engineering firm, Sproule Associates Limited, continued our record of capital efficiency. Highlights from our 2009 reserve report include:

- Proved plus probable ("2P") reserves totaled 197 mmboe, an increase of 5% from 2008. Our 2P reserve breakdown is 74% heavy oil, 15% light oil and 11% natural gas. At Seal, 2P reserves increased 39% to 55 mmboe. The steady reserve growth at Seal is consistent with our long-held view that this property holds significant potential.
- Exploration and development expenditures represented 47% of funds from operations, and led to a reserve replacement ratio[1] of 113%. Finding and development costs of $9.25 per boe, excluding future development capital ("FDC"), were consistent with our three-year average of $9.67 per boe.
- Inclusive of acquisitions, we replaced 165% of 2009 production. Finding, development, and acquisition costs of $11.63 per boe, excluding FDC, were on par with our three-year average of $11.89 per boe.
- In 2009, we generated an operating netback[2] of $27.64 per boe which led to a strong recycle ratio[2] of 2.4x. Our three-year average recycle ratio[2] is 2.5x.
- Our net asset value ("NAV") (before tax) increased to $32.16 per unit, up from $31.57 per unit at 2008.

(1) Reserve replacement ratio is calculated as total reserves added in the year divided by production for the same year.

(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable excluding FDC). Operating netback is calculated as revenue less royalties, operating expenses and transportation expenses.

Reserve Category	Reserve Value (C$millions) Before Tax and Discounted at: 10%	15%	20%
Proved			
Developed Producing	1,279	1,143	1,041
Developed Non-Producing	423	342	282
Undeveloped	1,033	785	619
Total Proved	2,735	2,270	1,942
Probable	1,098	821	642
Total Proved Plus Probable	3,833	3,091	2,584

Net Asset Value (Before Tax)	C$ Millions
PV10 of Proved plus Probable Reserves	3,833
Undeveloped Land	221
Year-end net debt	(467)
Asset retirement obligations	(55)
	3,532
Diluted trust units (millions)	109.8
Net asset value per trust unit	$32.16

Notes: Reserve value at December 31, 2009, as evaluated by Sproule Associates Limited. Undeveloped land and asset retirement obligation evaluated by Baytex. Diluted trust units outstanding include 0.53 million trust units issuable pursuant to outstanding convertible debentures. NAV calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by Sproule. It does not take into account the possibility of Baytex being able to recognize additional reserves through future capital investment in its existing properties beyond those included in the 2009 year-end report.

	Based on Forecast Prices and Costs							
	Light Oil & NGLs		Heavy Oil		Natural Gas		Oil Equivalent	
Reserve Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mboe)	Net (mboe)
Proved								
Developed Producing	8,068	6,038	31,358	25,997	68,546	57,494	50,850	41,617
Developed Non-Producing	1,003	742	16,334	13,782	11,781	8,882	19,300	16,005
Undeveloped	8,315	6,498	49,363	41,953	9,331	7,418	59,233	49,687
Total Proved	17,386	13,278	97,055	81,732	89,658	73,794	129,383	107,309
Probable	11,733	8,930	48,542	40,960	44,089	35,015	67,624	55,726
Total Proved Plus Probable	29,119	22,208	145,597	122,692	133,747	108,809	197,007	163,035

Notes: "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others. "Net" reserves means Baytex's gross reserves less all royalties payable to others. Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Please refer to our 2009 Annual Information Form, which can be found on our website at www.baytex.ab.ca, for complete reserves disclosure.

Environment, Health & Safety

Baytex Energy Trust has an Environmental, Health and Safety Policy to:

- develop and maintain health, safety and environmental management plans which include practices and procedures that comply with regulatory requirements and industry standards;
- ensure that all employees and contract personnel understand their responsibilities through education, communication and training;
- develop and maintain a contractor management program to ensure contractor and subcontractor compliance with Baytex policies;
- conduct regular reviews of the safety and environmental management system and conduct updates as required. Input from employees is encouraged and is considered when conducting reviews;
- conduct regular inspections and audits on all properties operated by Baytex; and
- develop emergency response plans and train employees to effectively respond to emergency situations.

Management is responsible for establishing health, safety and environmental policies and procedures and ensuring that all necessary resources, equipment and training are provided. In addition, corporate safety and environmental reports are presented periodically to the Board of Directors. All employees and contractors must understand and comply with all applicable policies and procedures.

In addition to the above, Baytex participates in the Canadian Association of Petroleum Producer's Environment, Health and Safety Stewardship program. This program has been developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. The program allows industry participants to measure the quality and performance of their environment, health and safety programs against other companies' programs. Baytex is proud to report that it has achieved a "Gold" ranking under this program for six years running.

Seal development has minimal land impact

BAYTEX ENERGY TRUST'S OPERATIONS ARE DESIGNED TO PROTECT THE HEALTH AND SAFETY OF OUR EMPLOYEES, CONTRACTORS, AND THE PUBLIC AND TO AVOID AN ADVERSE IMPACT ON THE ENVIRONMENT.

STEWARDSHIP

Five-Year Historical Summary

Year Ended December 31,	2009	2008	2007	2006	2005
FINANCIAL (thousands of Canadian dollars, except per unit amounts)					
troleum and natural gas sales	**789,820**	1,159,718	745,885	556,689	546,940
unds from operations[1]	**332,186**	433,823	286,030	274,662	227,465
Per unit - basic	**3.17**	4.73	3.57	3.77	3.38
Per unit - diluted	**3.10**	4.51	3.34	3.45	3.12
n distributions declared	**137,601**	197,026	145,927	143,072	114,221
Per unit	**1.56**	2.64	2.16	2.16	1.80
Net income	**87,574**	259,894	132,860	147,069	79,876
Per unit - basic	**0.83**	2.83	1.66	2.02	1.19
Per unit - diluted	**0.82**	2.74	1.60	1.91	1.15
Total monetary debt[1]	**474,276**	533,092	444,065	366,810	418,476
Operating netback (C$/boe)					
ales price	**45.00**	65.66	46.53	44.48	42.60
Financial instruments gain (loss)	**5.36**	(4.05)	(0.24)	0.20	(3.77)
Royalties	**(8.67)**	(13.99)	(7.70)	(6.80)	(6.38)
rating expenses	**(10.83)**	(11.62)	(10.09)	(8.98)	(8.62)
portation expenses	**(3.22)**	(2.83)	(2.31)	(1.95)	(1.74)
netback	**27.64**	33.17	26.19	26.95	22.09
Capital expenditures					
Exploration and development	**157,044**	184,678	148,719	132,381	130,492
Acquisitions, net of dispositions	**133,077**	265,099	245,427	702	21,957
Total capital expenditures	**290,121**	449,777	394,146	133,083	152,449
OPERATING					
ht oil & NGL (bbl/d)	**6,937**	7,575	5,483	3,735	3,842
Heavy oil (bbl/d)	**24,678**	23,530	22,092	21,325	21,265
Total oil (bbl/d)	**31,615**	31,105	27,575	25,060	25,107
Natural gas (mmcf/d)	**58.6**	54.8	51.9	55.4	60.4
Oil equivalent (boe/d @ 6:1)[2]	**41,382**	40,239	36,222	34,292	35,177
nt oil	**76%**	77%	76%	73%	71%
plus probable reser					
il & NGL (mmbbl)	**29.1**	31.4	20.8	11.7	12.7
Heavy oil (mmbbl)	**145.6**	126.1	122.5	108.7	97.6
Total oil (mmbbl)	**174.7**	157.5	143.3	120.4	110.3
Natural gas (bcf)	**133.7**	178.2	148.9	148.1	176.4
Oil equivalent (mmboe)[2]	**197.0**	187.1	168.1	145.1	139.7
value @ 10% pre-tax (C$/unit)	**32.16**	31.57	24.23	17.55	19.96
ts (proved plus probable, excluding FDC) (C$/boe)	**11.63**	13.11	10.90	7.31	4.70
ratio	**2.4**	2.5	2.4	3.7	4.7
TRUST UNIT INFORMATION					
Unit price (C$)					
High	**30.50**	35.37	22.92	28.66	18.78
Low	**9.77**	12.81	16.68	16.81	12.42
Close	**29.70**	14.65	19.00	22.28	17.70
verage daily volume traded	**446,799**	489,752	342,004	408,973	348,531
Init price (US$)					
High	**29.32**	35.20	21.74	25.87	-
Low	**7.84**	10.16	15.51	16.63	-
Close	**28.30**	11.95	19.11	18.96	-
ge daily volume traded	**131,908**	136,418	71,962	110,805	-
utstanding at December 31 (thousands)	**109,299**	97,685	87,169	77,498	71,475

1) Funds from operations and total monetary debt are non-GAAP terms. For further explanation refer to the Management's Discussion and Analysis for the year ended mber 31, 2009.

2) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil

3) Data reflects the periods since commencement of trading on March 27, 2006 on the NYSE

Corporate Information

DIRECTORS

Raymond T. Chan
Executive Chairman
Baytex Energy Ltd.

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

Edward Chwyl
Lead Independent Director
Independent Businessman

Naveen Dargan
Independent Businessman

R.E.T (Rusty) Goepel
Senior Vice President
Raymond James Ltd.

Anthony W. Marino
President & Chief Executive Officer
Baytex Energy Ltd.

Gregory K. Melchin
Independent Businessman

Dale O. Shwed
President & Chief Executive Officer
Crew Energy Inc.

OFFICERS

Raymond T. Chan
Executive Chairman

Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Exploration

Murray J. Desrosiers
Vice President,
General Counsel
and Corporate Secretary

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, U.S. Business Development

R. Shaun Paterson
Vice President, Marketing

Richard P. Ramsay
Vice President, Heavy Oil

Mark F. Smith
Vice President, Conventional Oil & Gas

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EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
°API	American Petroleum Institute gravity
bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
EUR	estimated ultimate recovery
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
mmboe	million barrels of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids

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Financial Report 2009

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Front Cover: Baytex heavy oil battery at Celtic, in the Lloydminster area of Saskatchewan

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust ("Baytex" or the "Trust") for the year ended December 31, 2009. This information is provided as of March 15, 2010. In this MD&A, references to "Baytex", the "Trust", "we", "us" and "our" and similar terms refer to Baytex Energy Trust and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Trust's audited consolidated comparative financial statements for the years ended December 31, 2009 and 2008, together with accompanying notes, and the Annual Information Form ("AIF") for the year ended December 31, 2009. The Trust's audited consolidated comparative financial statements, MD&A and AIF for the year ended December 31, 2009 will be filed in late March 2010. These documents and additional information about the Trust will be available on SEDAR at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentage and per unit amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

The Trust evaluates performance based on net income and funds from operations. Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers funds from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Distributions".

Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial instrument gains or losses)), the principal amount of long-term debt and the balance sheet amount of the convertible debentures.

Operating netback is a non-GAAP metric used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product. There is no standardized measure of operating netbacks and therefore operating netback as presented may not be comparable to similar measures presented by other companies. Operating netback is equal to product revenue less royalties, operating expenses and transportation expenses divided by a barrel of oil equivalent.

OUTLOOK – ECONOMIC ENVIRONMENT

The current economic environment continues to show signs of recovery from the recent financial crisis. This improving economic backdrop has contributed to the recent relative strength in oil prices. Sustaining this recent improvement in oil prices will depend on a combination of demand stabilization through economic recovery and natural production declines around the world due to reduced capital investment. In this economic environment Baytex is focused on the following objectives: preserving balance sheet strength and liquidity, maintaining and where possible, profitably expanding its productive capacity and delivering a sustainable distribution to its unitholders.

2009 OVERVIEW

Baytex Energy Trust is an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to a trust indenture. Baytex was established on September 2, 2003 in connection with a Plan of Arrangement of our subsidiary, Baytex Energy Ltd. (the "Company"). Through our subsidiaries, we are actively engaged in the exploration, development and production of oil, natural gas and natural gas liquids in Canada in the provinces of British Columbia, Alberta and Saskatchewan and in the United States in the states of North Dakota and Wyoming.

Our business objective has been to maintain production levels through investing approximately half of our internally generated cash flow into exploration and development ("E&D") activities while distributing most of the balance of our cash flow to holders of our trust units. Over our life, we have grown our reserve base and added to production levels through E&D activities complimented by strategic acquisitions.

During 2009, the Trust executed a successful capital program, resulting in the replacement of 113% of production (on a proved plus probable basis) by reinvesting 47% of our internally generated funds from operations into E&D activities. When acquisitions are included, the Trust replaced 165% of production.

As at December 31, 2009, we had a reserve base of 197 million (gross) boe on a proved plus probable basis. During the year ended December 31, 2009, our production averaged 41,382 boe/d, primarily from Canada.

On April 14, 2009, we completed a bought deal equity financing, issuing 7.9 million trust units for net proceeds of $109.0 million. Proceeds of this offering were used to repay bank debt.

On July 30, 2009, we closed the acquisition of certain oil and natural gas properties located primarily in the Kerrobert and Coleville areas of Saskatchewan. These assets were producing approximately 3,000 boe/d at the time of the acquisition, and the net purchase price was approximately $86.5 million. This acquisition was funded with a draw on our credit facilities.

On August 26, 2009, we closed the issuance of $150 million of senior unsecured debentures, and used the proceeds to partially fund the redemption of US$180 million of senior subordinated notes. The balance of redemption proceeds were funded with a draw on our credit facilities.

In December 2009, we prepaid the balance of our outstanding deferred land acquisition payments with respect to the North Dakota lands we obtained in 2008. This payment of US$33.2 million, which would otherwise have totaled US$36 million over approximately the next five to six quarters, provided greater and accelerated operating control over our interests in our North Dakota lands.

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2009	2008	Change
Daily Production			
Light oil and NGL (bbl/d)	**6,937**	7,575	(8%)
Heavy oil (bbl/d)[1]	**24,678**	23,530	5%
Natural gas (mmcf/d)	**58.6**	54.8	7%
Total production (boe/d)	**41,382**	40,239	3%
Production Mix			
Light oil and NGL	**17%**	19%	(11%)
Heavy oil	**60%**	58%	3%
Natural gas	**23%**	23%	0%

(1) *Heavy oil sales may differ from reported production volumes due to adjustments to Baytex's heavy oil inventory. In the year ended December 31, 2009 heavy oil sales were 91 bbl/d lower than production volume (December 31, 2008 – increase of 300 bbl/d).*

Total production for the year ended December 31, 2009 was 41,382 boe/d, a 3% increase from the year ended December 31, 2008 of 40,239 boe/d. For the year ended December 31, 2009, light oil and NGL production decreased by 8% to 6,937 bbl/d from 7,575 bbl/d last year due to production declines on conventional fields in Alberta and British Columbia. Heavy oil production for the year ended December 31, 2009 increased by 5% to 24,678 bbl/d compared to 23,530 bbl/d for 2008. Natural gas production increased by 7% to 58.6 mmcf/d for 2009 compared to 54.8 mmcf/d for 2008. The increase in production of both heavy oil and natural gas during 2009 was due primarily to the acquisition of producing assets in southwest Saskatchewan on July 30, 2009.

MARKETING

Crude Oil

In January 2009, as the global financial crisis deepened and most of the world's economies contracted, the price of oil (West Texas Intermediate, or "WTI") hit a low of US$32.70/bbl. However, as it became clear that the Organization of the Petroleum Exporting Countries ("OPEC") was largely adhering to its December 2008 pledge to curtail production by 4.2 million barrels per day, oil prices began an erratic but sustained increase that continued for the balance of 2009. Although global oil demand remained substantially below 2008 levels and global petroleum inventories remained high, particularly in the Organization for Economic Co-operation and Development ("OECD") countries, oil demand growth from non-OECD countries helped support oil prices as 2009 progressed. WTI reached a high of US$82.00/bbl in October 2009, capping a near US$50/bbl oil price increase from the low in January. As shown in the table below, the average price of WTI for the year ended December 31, 2009 was US$61.80/bbl, 38% lower than the average for 2008.

Compared to the volatility of WTI prices in 2009, the relative value of the Western Canadian Select ("WCS") heavy crude oil blend was less volatile than in 2008. As shown in the table below, the WCS differential averaged 16% for the year ended December 31, 2009, a significant improvement versus the respective 2008 discount of 22%. This improvement in heavy oil differentials resulted from a number of North American and global supply and demand factors, including increased demand from North American and Asian refineries that have been reconfigured to run more heavy oil, reduced output of heavy oil by traditional suppliers such as Mexico, and sufficient pipeline capacity from Canada to the U.S. to ensure access to a growing number of refineries.

Natural Gas

In contrast to oil's upward price trend in 2009, natural gas prices declined for much of the year as reflected in the table below. The average AECO price during 2009 was $4.14/mcf versus $8.13/mcf in 2008. The main drivers of the decline in natural gas prices in 2009 were two-fold: reduced demand by U.S. commercial and industrial consumers due to the economic downturn and sustained production from shale gas drilling. Although natural gas directed drilling activity declined significantly with the U.S. financial crisis, increased well productivity from horizontal drilling and multi-stage fracturing largely mitigated the reduced level of drilling activity. As a result, North American natural gas storage entered the winter of 2009/2010 at record levels, which depressed prices. Natural gas prices did rally in late 2009, due to the effects of sustained cold weather across much of the U.S. and Canada.

	Years Ended December 31		
	2009	2008	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 61.80	$ 99.59	(38%)
WCS heavy (US$/bbl)[2]	$ 52.14	$ 79.59	(34%)
Heavy oil differential[3]	(16%)	(22%)	(27%)
USD/CAD exchange rate	0.8760	0.9371	(7%)
Edmonton par oil ($/bbl)	$ 66.20	$ 102.86	(36%)
AECO natural gas price ($/mcf)[4]	$ 4.14	$ 8.13	(49%)
Baytex Average Sales Prices			
Light oil and NGL ($/bbl)	$ 54.25	$ 88.92	(39%)
Heavy oil ($/bbl)[5][6]	$ 55.01	$ 72.84	(24%)
Physical forward sales contracts (loss) ($/bbl)	(5.13)	(7.62)	(33%)
Heavy oil, net ($/bbl)	$ 49.88	$ 65.22	(24%)
Total oil and NGL, net ($/bbl)	$ 50.85	$ 70.94	(28%)
Natural gas ($/mcf)[6]	$ 4.09	$ 8.11	(50%)
Physical forward sales contracts gain (loss) ($/mcf)	0.26	(0.19)	(237%)
Natural gas, net ($/mcf)	$ 4.35	$ 7.92	(45%)
Summary			
Weighted average ($/boe)[6]	$ 48.23	$ 71.49	(33%)
Physical forward sales contracts gain (loss) ($/boe)	(3.23)	(5.83)	(45%)
Weighted average, net ($/boe)	$ 45.00	$ 65.66	(31%)

(1) WTI refers to the calendar monthly average based on Nymex prompt month WTI.
(2) WCS refers to the posting price of the benchmark heavy oil price.
(3) Heavy oil differential refers to the WCS discount to WTI.
(4) AECO refers to the AECO monthly published Canadian Gas Price Reporter posting.
(5) Baytex's realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(6) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage heavy oil). The above table excludes impact of financial instruments.

For the full year 2009, Baytex's average sales price for light oil and NGL was $54.25/bbl, down 39% from $88.92/bbl in 2008. Baytex's realized heavy oil price in 2009, prior to physical forward sales contracts was $55.01/bbl, or 92% of the benchmark WCS price. The differential to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price in 2009 was $49.88/bbl, down 24% from $65.22/bbl in 2008. Baytex's realized natural gas price in 2009 was $4.09/mcf, prior to physical forward sales contracts, and $4.35/mcf inclusive of physical forward sales contracts.

Revenue

($ thousands except for %)	Years Ended December 31 2009	2008	Change
Oil revenue			
Light oil and NGL	$ 137,379	$ 246,516	(44%)
Heavy oil	447,674	568,841	(21%)
Total oil revenue	585,053	815,357	(28%)
Natural gas revenue	93,132	158,845	(41%)
Total oil and natural gas revenue	678,185	974,202	(30%)
Sulphur revenue	786	6,820	(88%)
Other income	77	2,000	(96%)
Sales of heavy oil blending diluent	110,772	176,696	(37%)
Total petroleum and natural gas sales	$ 789,820	$ 1,159,718	(32%)

For the year ended December 31, 2009, light oil and NGL revenue decreased 44% from the same period last year due to a 39% decrease in wellhead prices and an 8% decrease in sales volume. Revenue from heavy oil decreased 21% percent due to a 24% decrease in wellhead prices, offset by a 5% increase in volumes. Revenue from natural gas decreased 41% compared to 2008 primarily due to a 45% decrease in realized commodity price offset by a 7% increase in production.

For the year ended December 31, 2009, sulphur production averaged 45.9 tonnes per day with an average price of $47 per tonne, as compared to 48.9 tonnes per day with an average price of $381 per tonne in 2008.

Royalties

($ thousands except for % and per boe)	Years Ended December 31 2009	2008	Change
Royalties	$ 130,715	$ 207,522	(37%)
Average royalty rate[(1)]	19.3%	21.2%	(9%)
Royalty expenses per boe	$ 8.67	$ 13.99	(38%)

(1) Royalty rate excludes sales of heavy oil blending diluents and the effects of financial instruments.

For the year ended December 31, 2009, royalties decreased to $130.7 million from $207.5 million for 2008. Total royalties for 2009 were 19.3% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent and other), as compared to 21.2% for 2008. For 2009, royalties were 20.5% of revenue for light oil, NGL and natural gas (2008 – 23.0%) and 18.7% for heavy oil (excluding sales of heavy oil blending diluent and other), (2008 – 19.8%). The decrease of 9% in the overall royalty rate is primarily due to lower commodity prices and new Alberta royalty incentive programs. Certain additional credits earned under the Alberta Royalty Drilling Credit program which are based on drilling activity and drilling depths are recorded as a reduction to capital expenditures, rather than as a reduction in royalties.

Financial Instruments

($ thousands)	Years Ended December 31 2009	2008	Change
Realized gain (loss) on financial instruments[1]			
Crude oil	$ 62,076	$ (51,367)	$ 113,433
Natural gas	3,565	–	3,565
Foreign currency	15,177	(8,734)	23,911
Total	$ 80,818	$ (60,101)	$ 140,919
Unrealized gain (loss) on financial instruments[2]			
Crude oil	$ (77,093)	$ 115,910	$ (193,003)
Natural gas	(1,142)	–	(1,142)
Foreign currency	23,804	4,007	19,797
Interest swaps	(379)	–	(379)
Total	$ (54,810)	$ 119,917	$ (174,727)
Total gain (loss) on financial instruments			
Crude oil	$ (15,017)	$ 64,543	$ (79,560)
Natural gas	2,423	–	2,423
Foreign currency	38,981	(4,727)	43,708
Interest swaps	(379)	–	(379)
Total	$ 26,008	$ 59,816	$ (33,808)

(1) Realized gain (loss) on financial instruments represents actual cash settlement or receipts under the respective financial instruments.

(2) Unrealized gain (loss) on financial instruments represents the change in fair value of the financial instruments during the year.

The gain on financial instruments for the year ended December 31, 2009 was $26.0 million compared to a gain of $59.8 million in 2008. The realized gain of $80.8 million in 2009 is mostly attributable to crude oil and foreign currency contracts. The 2009 realized gain is offset by unrealized mark-to-market losses of $54.8 million compared to $60.1 million in realized losses and $119.9 million in unrealized gains in the year ended 2008. The significant unrealized mark-to-market gain in the year ended December 31, 2008 was due to the significant decline in the crude oil price at the end of 2008 compared to the end of 2007. The unrealized mark-to-market loss on the crude oil contracts results from the change in fair value of the contracts during the period.

Details of the risk management contracts in place as at December 31, 2009, and the accounting for the Trust's financial instruments are disclosed in note 18 to the consolidated financial statements.

Operating Expenses

($ thousands except for % and per boe)	Years Ended December 31 2009	2008	Change
Operating expenses	$ 163,250	$ 172,471	(5%)
Operating expenses per boe	$ 10.83	$ 11.62	(7%)

Operating expenses for the year ended December 31, 2009 decreased to $163.3 million from $172.5 million in 2008. Operating expenses were $10.83 per boe for 2009 compared to $11.62 per boe for the prior year. In 2009, operating expenses were $11.70 per boe of light oil, NGL and natural gas and $10.24 per barrel of heavy oil, as compared to $11.73 and $11.55, respectively, in 2008. In the case of heavy oil, the reduction in per barrel operating expense is a result of reductions in the cost of energy and services inputs as well as higher production levels.

Transportation and Blending Expenses

Transportation and blending expenses for the year ended December 31, 2009 were $159.4 million compared to $218.7 million for 2008.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex mainly purchases condensate from industry producers as the blending diluent to facilitate the marketing of its heavy oil. The cost of diluent is effectively recovered in the sale price of a blended product. For the year ended December 31, 2009, the blending cost was $110.8 million for the purchase of 4,240 bbl/d of condensate at $71.58 per barrel, as compared to $176.7 million for the purchase of 4,377 bbl/d at $110.30 per barrel in 2008.

	Years Ended December 31		
($ thousands except for % and per boe)	2009	2008	Change
Transportation expenses[1]	$ 48,582	$ 42,010	16%
Transportation expense per boe[1]	$ 3.22	$ 2.83	14%

(1) Transportation expenses are before the purchase of blending diluent.

Transportation expenses for 2009 include $1.0 million related to the transportation of sulphur compared to $1.3 million in the year ended in 2008. Transportation expenses before blending costs were $3.22 per boe for 2009 compared to $2.83 per boe in 2008. Transportation expenses were $0.79 per boe of light oil, NGL and natural gas and $4.88 per barrel of heavy oil in 2009, compared to $0.86 and $4.22, respectively, in 2008.

Operating Netback

	Years Ended December 31		
($ per boe except for % and volume)	2009	2008	Change
Sales volume (boe/d)	41,291	40,539	2%
Operating netback ($/boe)[1]:			
Sales price[2]	$ 45.00	$ 65.66	(32%)
Less:			
Royalties	8.67	13.99	(38%)
Operating expenses	10.83	11.62	(7%)
Transportation expenses	3.22	2.83	14%
Operating netback before hedging	$ 22.28	$ 37.22	(40%)
Financial instruments gain (loss)[3]	5.36	(4.05)	232%
Operating netback after hedging	$ 27.64	$ 33.17	(17%)

(1) Netback table includes revenues and costs associated with sulphur production.
(2) Sales prices are shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial instruments reflect realized derivative gains (losses) only.

General and Administrative Expenses

	Years Ended December 31		
($ thousands except for % and per boe)	2009	2008	Change
General and administrative	$ 35,006	$ 29,603	18%
General and administrative per boe	$ 2.32	$ 2.00	16%

General and administrative expenses for the year ended December 31, 2009 were $35.0 million, compared to $29.6 million for the prior year. The increase is primarily attributable to a $3.4 million non-recurring tax indemnification payment made on behalf of certain employees who experienced unintended adverse U.S. income tax consequences related to participation in our trust unit rights incentive plan. Excluding this one-time item, G&A

per boe would have been $2.10 per boe for 2009 compared to $2.00 per boe in 2008. Including this one time item, on a per sales unit basis, G&A expenses were $2.32 per boe in 2009. During 2009, higher consulting and office costs were incurred in Canada and the U.S. due to a full year of expenses associated with the expansion of the Denver office to manage our U.S. operations. This increase was partially offset by higher operating overhead recoveries compared to the prior year.

Unit-based Compensation Expense

For the year ended December 31, 2009, compensation expense was $6.4 million, a decrease of 18% compared to $7.8 million for the same period in 2008. Compensation expense associated with our trust unit rights incentive plan is recognized in income over the vesting period of the rights with a corresponding increase in contributed surplus. The exercise of rights is recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Interest Expense

Interest expense for the year ended December 31, 2009 was $32.7 million compared to $32.5 million in 2008. Interest on the bank loan decreased by $1.9 million compared to the year ended December 31, 2008. This is offset by the recognition of the remaining $1.6 million of accretion expense on the discounted fair value hedge upon retirement of the senior subordinated notes at September 25, 2009.

Financing Charges

Financing charges for the year ended December 31, 2009 increased to $5.5 million compared to $0.5 million in 2008. The majority of the increase consists of transaction costs of $3.6 million for the issuance of $150 million of senior unsecured debentures on August 26, 2009 as well as a commitment fee of $1.8 million to amend and extend the credit facility.

Foreign Exchange

Foreign exchange gain for the year ended December 31, 2009 was $22.8 million compared to a loss of $37.7 million in the prior year. The major component of the realized gain for 2009 is the gain of $23.7 million realized on the retirement of the US$ senior subordinated notes ($nil for 2008) on September 25, 2009. The loss for the year ended December 31, 2008 is based on the translation of the US$ senior subordinated notes at 1.2246 USD/CAD compared to 0.9881 USD/CAD at December 31, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $237.2 million for the year ended December 31, 2009 compared to $223.9 million in 2008. On a sales-unit basis, the provision for the current year was $15.74 per boe compared to $15.09 per boe in 2008. The increase is attributable to a higher capital base due to the acquisition of the assets in southwest Saskatchewan on July 30, 2009.

Taxes

Current tax expense of $11.4 million for the year ended December 31, 2009 is $1.2 million higher than the $10.2 million recorded in 2008.

As at December 31, 2009, total future tax liability of $186.6 million (December 31, 2008 – $217.8 million) consisted of a $1.4 million current future tax asset (December 31, 2008 – $nil), $0.4 million long-term future tax asset (December 31, 2008 – $nil), $8.7 million current future tax liability (December 31, 2008 – $25.4 million) and a $179.7 million long-term future tax liability (December 31, 2008 – $192.4 million). The decrease from the prior year is

due to lower funds from operations and recognition of non-capital losses previously included in the valuation allowance.

Tax Pools

($ thousands)	December 31, 2009	December 31, 2008
Cumulative Canadian oil and gas property expense	$ 299,220	$ 217,260
Cumulative Canadian development expense	189,791	193,319
Cumulative Canadian exploration expense	–	53,047
Undepreciated capital cost	241,071	249,306
Other	19,639	27,741
Total Canadian tax pools	$ 749,721	$ 740,673
Taxable depletion	$ 148,031	$ 113,520
Tangibles	3,686	2,133
Intangible drilling costs	9,182	1,132
Other	4,178	–
Total U.S. tax pools	$ 165,077	$ 116,785

Net Income

Net income for the year ended December 31, 2009 was $87.6 million compared to $259.9 million for the same period in 2008. Revenues, net of royalties, decreased $293.1 million or 31% for the year ended December 31, 2009 compared to the same period in 2008. This decrease is attributable to lower commodity prices for the full year 2009, partially offset by a decrease of $9.2 million in operating expenses for the year ended December 31, 2009 compared to the same period in 2008. Other factors that offset the decrease in revenues, net of royalties, included a $59.3 million decrease in transportation and blending expenses, a $60.6 million increase in foreign exchange gain and a $45.8 million increase in the future tax recovery.

Other Comprehensive Loss

The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date (0.9555 USD/CAD), while revenues and expenses are translated using the average exchange rate for the year ended December 31, 2009 (0.9467 USD/CAD). Translation gains and losses are deferred and included in other comprehensive income in unitholders' capital and are recognized in net income when there has been a reduction in the net investment.

Previously, foreign operations were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate while other assets and liabilities were translated at the historical rate. Revenues and expenses were translated at the average monthly rate except for depletion, depreciation and accretion, which were translated on the same basis as the assets to which they relate. Translation gains and losses were included in the determination of net income for the period.

This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties. An addition of $3.4 million, a reduction of $9.8 million, a reduction of $9.7 and a reduction of $3.2 million were recognized in the first, second, third and fourth quarters of 2009, respectively, resulting in a balance of $3.9 million in accumulated other comprehensive loss at December 31, 2009.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DISTRIBUTIONS

Funds from operations and payout ratio are non-GAAP terms. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's payout ratio is calculated as cash distributions (net of participation in the Distribution Reinvestment Plan ("DRIP")) divided by funds from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund distributions and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to funds from operations (a non-GAAP measure):

	Years Ended December 31	
($ thousands except for %)	**2009**	2008
Cash flow from operating activities	**$ 303,162**	$ 471,237
Change in non-cash working capital	**27,878**	(38,857)
Asset retirement expenditures	**1,146**	1,443
Funds from operations	**$ 332,186**	$ 433,823
Cash distributions declared(1)	**$ 137,601**	$ 197,026
Payout ratio	**41%**	45%

(1) Cash distributions declared are net of DRIP participation.

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions declared, net of DRIP participation, of $137.6 million for the year ended December 31, 2009 were funded through funds from operations of $332.2 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	Years Ended December 31	
($ thousands except for %)	**2009**	2008
Cash flow from operating activities	**$ 303,162**	$ 471,237
Cash distributions declared	**137,601**	197,026
Excess of cash flow from operating activities over cash distributions declared	**$ 165,561**	$ 274,211
Net income	**$ 87,574**	$ 259,894
Cash distributions declared	**137,601**	197,026
Excess (shortfall) of net income over cash distributions declared	**$ (50,027)**	$ 62,868

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures for exploration and development activities through funds from operations. Future production levels are highly dependent upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized, are the main factors influencing the sustainability of our cash distributions. During periods of lower commodity prices, or periods of higher capital spending, it is possible that funds from operations will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

As at December 31, 2009, Baytex had approximately $198 million in available undrawn credit facilities to fund any such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital. For the year ended December 31, 2009, the Trust's cash distributions declared exceeded net income by $50.0 million, with net income reduced by $215.6 million for non-cash items. Non-cash items such as depletion, depreciation and accretion may not be fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

LIQUIDITY AND CAPITAL RESOURCES

As a result of the recent economic crisis, there have been periodic disruptions in the availability of credit. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties, and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium, and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2009, total net monetary debt was $474.3 million compared to $533.0 million at the end of 2008. Bank borrowings and working capital deficiency at the end of 2009 were $316.5 million compared to total credit facilities of $515.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates or LIBOR rates, plus applicable margins. The credit facilities were increased from $485.0 million to $515.0 million in June 2009. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of our assets.

The credit facilities were arranged pursuant to an agreement with a syndicate of financial institutions. A copy our credit agreement and related amendments are accessible on the SEDAR website at www.sedar.com (filed on March 28, 2008, September 15, 2008, July 9, 2009, August 14, 2009 and October 5, 2009).

In August 2009, Baytex closed its offering of $150 million principal amount of 9.15% Series A senior unsecured debentures due August 26, 2016. Baytex used the net proceeds from the offering of the debentures of $147 million (after agents' fees but before deduction of other offering expenses), along with funds drawn on its credit facilities, to fund the redemption price for the following senior subordinated notes of its subsidiary, Baytex Energy Ltd.: 9.625% notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% notes due February 15, 2011 (principal amount US$0.2 million).

Pursuant to various agreements with our lenders, we are restricted from making distributions to unitholders where the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities upon a material borrowing base shortfall or default.

The Trust believes that cash flow generated from operations, together with the existing credit facilities, will be sufficient to finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary, and the Trust has the ability to modify distribution levels should funds from operations be negatively impacted by factors such as reduction in commodity prices.

Capital Expenditures

Capital expenditures are summarized as follows:

	Years Ended December 31	
($ thousands)	**2009**	2008
Land	**$ 13,514**	$ 9,534
Seismic	**2,222**	4,947
Drilling and completion	**113,959**	132,296
Equipment	**26,164**	34,720
Other	**1,185**	3,181
Total exploration and development	**$ 157,044**	$ 184,678
Corporate acquisition	**$ –**	$ 180,467
Property acquisitions	**133,155**	84,826
Property dispositions	**(78)**	(194)
Total oil and natural gas expenditures	**$ 290,121**	$ 449,777
Corporate assets	**7,050**	405
Total capital expenditures	**$ 297,171**	$ 450,182

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. As at March 5, 2010, the Trust had 110,347,769 trust units issued and outstanding.

At March 5, 2010, the Trust had a principal amount of $7.2 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit. The convertible debentures mature on December 31, 2010, at which time they are due and payable.

Non-controlling Interest

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this retirement, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008 of 1.79560. As at December 31, 2008, there were no exchangeable shares outstanding.

Off Balance Sheet Arrangements

Baytex is not party to any contractual arrangement under which a non-consolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. Baytex has no obligation under financial instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Trust, or engages in leasing, hedging or research and development services with the Trust.

Contractual Obligations

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring nature and impact the Trust's funds from operations in an on-going manner. A significant portion of these obligations will be funded through funds from operations. These obligations as of December 31, 2009, and the expected timing of funding of these obligations are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	$ 180,493	$ 180,493	$ –	$ –	$ –
Distributions payable to unitholders	19,674	19,674	–	–	–
Bank loan(1)	265,088	265,088	–	–	–
Long-term debt(2)	150,000	–	–	–	150,000
Convertible debentures(2)	7,815	7,815	–	–	–
Operating leases	40,014	3,408	7,659	7,499	21,448
Processing and transportation agreements	7,708	4,328	3,251	129	–
Total	$ 670,792	$ 480,806	$ 10,910	$ 7,628	$ 171,448

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. Unless extended, the bank loan will mature on June 30, 2010.

(2) Principal amount of instruments.

The Trust also has on-going obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

RISK MANAGEMENT

Financial Instruments and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, fluctuations in commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future petroleum and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of members of the Board of Directors of the Company (the "Board"), assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective of the risk management program is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar borrowings. The related foreign exchange gains and losses are included in net income.

The Trust is exposed to changes in interest rates as the Company's credit facilities are based on the lenders' prime lending rate, LIBOR, and short-term bankers' acceptance rates.

Details of the risk management contracts in place as at December 31, 2009, and the accounting for the Trust's financial instruments are disclosed in note 18 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2009 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 1 and 2 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. The financial and operating results of the Trust incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and natural gas reserves that the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

The Trust has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Recent Accounting Changes

Effective January 1, 2009, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") accounting standards Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The adoption of this new standard did not have a material impact on the consolidated financial statements of the Trust.

Effective January 1, 2009, the Trust adopted the CICA issued EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". EIC-173 provides guidance on how to take into account the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 did not have a material impact on the consolidated financial statements of the Trust.

In June 2009, the CICA amended Section 3862 "Financial Instruments – Disclosures" to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. The Trust adopted this standard prospectively effective December 31, 2009. The adoption of this amended standard did not have a material impact on the consolidated financial statements of the Trust.

Effective July 1, 2009, the Trust prospectively adopted the CICA amended section 3855, "Financial Instruments – Recognition and Measurement", in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and, provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The Trust adopted this standard prospectively effective December 31, 2009. The adoption of this amended standard did not have a material impact on the consolidated financial statements of the Trust.

Future Accounting Changes

In January 2009, the CICA issued Section 1582 "Business Combinations" which establishes principles and requirements of the acquisition method for business combinations and related disclosures. The purchase price is to be based on trading data at the closing date of the acquisition, not the announcement date of the acquisition, and most acquisition costs are to be expensed as incurred. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting of future business combinations.

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" which establishes standards for the preparation of consolidated financial statements and Section 1602 "Non-controlling Interests" which provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting of future business combinations.

International Financial Reporting Standards ("IFRS")

In October 2009, the Accounting Standards Board ("AcSB") issued a third IFRS Omnibus Exposure Draft confirming that IFRS will replace Canadian GAAP for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Baytex for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

Throughout 2009 the Trust has assessed the impact of adopting IFRS and is continuing to implement plans for transition. The key elements include analyzing accounting policy alternatives, process changes, internal control requirements and information system changes.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact on the financial statements of adopting IFRS. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to the Trust's adoption of IFRS, Management's plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

First-Time Adoption of IFRS

IFRS 1, "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1"), provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for Baytex. At this time, the Trust anticipates it will apply the following exemptions:

Property, plant and equipment ("PP&E") – IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date.

Business combinations – IFRS 1 permits the use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based payments – IFRS 1 provides an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vested before the Trust's transition date to IFRS.

Cumulative translation differences – An option is available to deem cumulative translation differences on all foreign operations as zero at the date of transition.

Key Accounting Policy Differences

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. At this time, Baytex has identified key differences that will impact the financial statements as follows:

Exploration and Evaluation ("E&E") expenditures – On transition to IFRS Baytex will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheet. This will consist of the book value of undeveloped land that relates to exploration properties. Baytex will initially capitalize these costs as E&E assets on the balance sheet. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.

Depletion expense – Under IFRS, costs will be depleted on a unit of production basis at a more granular level than the country level. The Trust has the option to base the depletion calculation using either total proved or proved plus probable reserves. Baytex has not concluded at this time which method it will use.

Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating

unit level using either total proved or proved plus probable reserves. Impairment losses are reversed under IFRS when there is an increase in the recoverable amount.

Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009 and the issuance of the exposure draft on IAS 37 Provisions, Contingent Liabilities and Contingent Assets in January 2010, Management is still determining the impact of these revised standards on its IFRS transition.

Internal Controls Over Financial Reporting and Disclosure Controls and Procedures

During 2010, the Trust will continue to assess the impact of the adoption of IFRS on internal controls over financial reporting to ensure all changes in accounting polices include appropriate additional controls and procedures for future IFRS reporting requirements.

In regards to disclosure controls and procedures, Baytex will be assessing stakeholders' information requirements and ensure that appropriate and timely information is provided once available.

Information Technology Systems

As a result of Baytex's evaluation of our Information Technology systems, modifications have been made to the accounting systems to accommodate the additional requirements under IFRS. The modifications were not significant, however, deemed critical in order to allow for reporting of both Canadian GAAP and IFRS financial statements in 2010. Additional system modifications may be required based on final accounting policy choices.

TRUST INFORMATION

The Trust is authorized to issue an unlimited number of trust units. As at March 10, 2010, the Trust had 110,367,157 trust units issued and outstanding.

At March 10, 2010, the Trust had a principal amount of $7.1 million of convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit. The convertible debentures mature on December 31, 2010, at which time they are due and payable.

Effective August 29, 2008, all of the outstanding exchangeable shares were purchased by Baytex ExchangeCo Ltd. for consideration of 1.79560 trust units for each exchangeable share.

SELECTED ANNUAL INFORMATION

($ thousands, except per unit amounts)	2009	2008	2007
Petroleum and natural gas sales	789,820	1,159,718	745,885
Net income(1)	87,574	259,894	132,860
Per unit basic(1)	0.83	2.83	1.66
Per unit diluted(1)	0.82	2.74	1.60
Total assets	1,884,005	1,812,333	1,407,150
Total long-term financial liabilities	150,000	227,468	190,004
Cash distributions declared per unit	1.56	2.64	2.16

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2009 was 41,382 boe/d which represented a 3% increase from 40,239 boe/d in 2008 and a 14% increase from 36,222 boe/d in 2007. Average wellhead prices net of blending costs received were $45.00 per boe during 2009, $65.66 per boe during 2008 and $46.53 per boe during 2007.

FOURTH QUARTER 2009

For a discussion and analysis of our operating and financial results for the three months ended December 31, 2009, please see our Management's Discussion and Analysis for the three months and year ended December 31, 2009 dated March 10, 2010, which is incorporated by reference into this MD&A and is accessible on SEDAR at www.sedar.com.

2010 GUIDANCE

Baytex has set a 2010 exploration and development capital budget of $235 million designed to generate production levels at an average annual rate of 43,500 boe/d. Approximately 60% of this budget will be directed towards our heavy oil operations program, with the single largest project being horizontal cold well development at our Seal heavy oil resource play in the Peace River oil sands. The balance of our program will be directed towards our light oil and natural gas operations in Canada and the United States with the largest project being our Bakken/Three Forks light oil development in North Dakota.

ENVIRONMENTAL REGULATION AND RISK

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs.

Climate Change Regulation

The Government of Canada ratified the Kyoto Protocol in 2002, calling for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels by 2012. In December 2009, representatives of approximately 170 countries meet in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The Copenhagen negotiations resulted in the Copenhagen Accord, a non-binding political accord which reinforced the Kyoto Protocol's commitment to reducing greenhouse gas emissions. In response to the Copenhagen Accord, the government of Canada revised its emissions reduction goals and now aims to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. Despite the commitments made under the Kyoto Protocol and the Copenhagen Accord, no federal legislation has been implemented to regulation the emission of greenhouse gases and the Government of Canada has indicated that it will delay the implementation of climate change legislation and regulations in order to ensure consistency with the approach ultimately taken by the United States with respect to greenhouse gas emissions.

There has been much public debate with respect to Canada's ability to meet these targets and the Government of Canada's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The implementation of strategies for reducing greenhouse gases, whether to meet the goals of the Kyoto Protocol, the Copenhagen Accord or otherwise could have a material impact on the nature of oil and natural gas operations, including those of Baytex. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our operations and financial condition.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2009 under the Industry Conditions section.

The New Royalty Framework

On October 25, 2007, the Alberta government announced the "New Royalty Framework" ("NRF"), which introduced the following changes to Alberta's royalty regime effective January 1, 2009:

- Conventional oil – overall royalty rates increased from the pre-NRF maximum of 30% and 35% for old and new tiers. The NRF rates vary on a sliding scale basis up to 50%, and rate caps have been raised to $120 per barrel for West Texas Intermediate crude.
- Natural gas – the Government eliminated "old" and "new" tiers. Royalty rates, pre-NRF at 5% to 35% increased to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at $17.75 per gigajoule.
- Oil Sands – before NRF, the pre-payout royalty rate was 1%. Under the NRF, this rate increased for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the previous regime, once an oil sands project reached payout, the 1% royalty converted to a 25% net profits interest. Under the NRF, the net profits interest applies at the rate of 25% when oil is less than $55 per bbl of WTI, and increases for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Alberta government announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. Companies drilling new natural gas or conventional oil deep wells between 1,000 and 3,500 metres are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty rates will revert to royalty rates determined by the NRF.

On March 3, 2009, the Alberta government announced a new well incentive program intended to stimulate conventional drilling activity. The incentive program offers a one-year royalty credit for conventional oil and gas wells drilled between April 1, 2009 and March 31, 2010 of $200 per metre and also provides for a maximum 5% royalty for all new wells that begin producing conventional oil and gas between during the same period. In June 2009, the Alberta government announced the extension of these incentive programs for until March 31, 2011.

On August 6, 2009, the British Columbia ("B.C.") government announced a stimulus package to boost the current economy by introducing changes to the B.C. royalty program. These changes include a one-year, 2% royalty rate for the first year of production on wells drilled in a 10 month window from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010; a permanent increase of 15% in the existing Deep Royalty Credit Program for both vertical and horizontal wells; and a permanent change in the Deep Royalty Credit Program to include horizontal wells drilled between 1,900 and 2,300 metres, which is shallower than the previous cut-off of 2,300 metres.

Further information regarding NRF and current provincial royalties and incentive programs is contained in our Annual Information Form for the year ended December 31, 2009 under the Industry Conditions section.

Broad-based Federal Tax Reductions

On October 30, 2007, the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the SIFT tax rate to equal the federal corporate income tax rate plus the provincial SIFT tax rate, discussed below.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law amendments to the Income Tax Act (Canada) (the "Tax Act") that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "SIFT"), such as Baytex, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "SIFT Rules"). Currently, the SIFT Rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax rate. The provincial SIFT Tax rate will be based on the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable provincial allocation formula will be used. Specifically, the Trust's taxable distributions, if any, will be allocated to provinces by taking half of the aggregate of: (i) that proportion of the Trust's taxable distributions, if any, for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and (ii) that proportion of the Trust's taxable distributions, if any, for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada. The Trust's main permanent establishment is anticipated to be in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011. Taxable distributions, if any, that are not allocated to any province, would instead be subject to a 10% rate constituting the provincial component.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. For the Trust, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of the subsequent three years. On December 4, 2008, the Federal Minister of Finance announced changes to the guidelines discussed above to allow a SIFT to accelerate the utilization of the SIFT annual safe harbour amount for each of 2009 and 2010 so that the safe harbour amounts for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT, but it allows a SIFT to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years. The Trust did not issue equity in excess of the safe harbour limits during 2006, 2007, 2008 or 2009. The Trust issued $165.9 million equity during the year ended December 31, 2009 resulting in an unused available safe harbour amount of $1,160.7 million as at December 31, 2009.

On July 14, 2008, the Federal Minister of Finance announced proposed amendments to the Tax Act, including technical amendments to clarify certain aspects of the SIFT Rules and to provide rules to facilitate the conversion of existing SIFTs into corporations on a tax-deferred basis (the "Conversion Rules"). The Conversion Rules address many of the principal substantive and administrative issues that arise when structuring a corporate conversion of an income trust under the Tax Act. The Conversion Rules contemplate two alternatives for the conversion of a publicly-traded SIFT into a taxable Canadian corporation and the winding-up of the SIFT's underlying structure. The first alternative involves the winding-up of the SIFT into a taxable Canadian corporation whereas the second approach involves the distribution by the publicly-traded SIFT of shares of an underlying taxable Canadian corporation to its unitholders. The Conversion Rules will generally only apply to the winding-up of a SIFT or a distribution of shares completed after July 14, 2008 and before 2013. Bill C-10, which received Royal Assent on March 12, 2009, contained legislation implementing the Conversion Rules. We are planning to complete a conversion transaction from the current trust structure to a corporate legal form to be completed before the end of 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

Disclosure Controls and Procedures

As of December 31, 2009, an evaluation was conducted of the effectiveness of the Trust's "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) by management, with the participation of the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Trust's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Trust's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Trust's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. "Internal control over financial reporting" (as defined in the United States by Rules 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the Trust's internal control over financial reporting as of December 31, 2009. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2009. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 has been audited by Deloitte & Touche LLP, as reflected in their report for 2009.

No changes were made to our internal control over financial reporting during the year ended December 31, 2009, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "on-going", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: our ability to maintain production levels by investing approximately half of our funds from operations into exploration and development activities; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; our ability to fund our capital expenditures and distributions on our trust units from funds from operations; the sufficiency of our capital resources to meet our on-going short, medium and

long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash distributions and capital program; the timing of funding our financial obligations; the impact of the adoption of new accounting standards on our financial statements; the impact of the adoption of IFRS on our financial position and results of operations; our exploration and development capital program for 2010 and the allocation thereof to various projects; our average production rate for 2010; the impact of environmental and climate change regulations on our operations; the taxation of income trusts; and potential changes to our business form. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Trust is responsible for establishing and maintaining adequate internal control over financial reporting over the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2009, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect the financial statement preparation and presentation.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 has been audited by Deloitte & Touche LLP, the Trust's Independent Registered Chartered Accountants, who also audited the Trust's Consolidated Financial Statements for the year ended December 31, 2009.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Chartered Accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of Deloitte & Touche LLP and reviews their fees. The Independent Registered Chartered Accountants have access to the Audit Committee without the presence of management.

Anthony W. Marino
President and Chief Executive Officer
Baytex Energy Ltd.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Ltd.

March 15, 2010

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors of Baytex Energy Ltd. and Unitholders of Baytex Energy Trust:

We have audited the consolidated balance sheets of Baytex Energy Trust and subsidiaries (the "Trust") as at December 31, 2009 and 2008, and the consolidated statements of income and comprehensive income, deficit, and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2010 expressed an unqualified opinion on the Trust's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Trust's financial statements, such as the changes described in Notes 3 and 21 to the consolidated financial statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Unitholders of Baytex Energy Trust, dated March 15, 2010, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors of Baytex Energy Ltd. and Unitholders of Baytex Energy Trust:

We have audited the internal control over financial reporting of Baytex Energy Trust and subsidiaries (the "Trust") as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of the Trust and our report dated March 15, 2010 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to changes in accounting principles.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

CONSOLIDATED BALANCE SHEETS

As at December 31	2009	2008
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Cash	$ 10,177	$ –
Accounts receivable	137,154	87,551
Crude oil inventory	1,384	332
Future income tax asset (note 15)	1,371	–
Financial derivative contracts (note 18)	29,453	85,678
	179,539	173,561
Future income tax asset (note 15)	418	–
Financial derivative contracts (note 18)	2,541	–
Petroleum and natural gas properties (note 5)	1,663,752	1,601,017
Goodwill	37,755	37,755
	$ 1,884,005	$ 1,812,333
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities (note 18)	$ 180,493	$ 164,353
Distributions payable to unitholders (note 18)	19,674	17,583
Bank loan (note 18)	265,088	208,482
Convertible debentures (note 8)	7,736	–
Future income tax liability (note 15)	8,683	25,358
Financial derivative contracts (note 18)	4,650	–
	486,324	415,776
Long-term debt (note 7)	150,000	217,273
Convertible debentures (note 8)	–	10,195
Asset retirement obligations (note 9)	54,593	49,351
Future income tax liability (note 15)	179,673	192,411
Financial derivative contracts (note 18)	1,418	–
	872,008	885,006
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	1,295,931	1,129,909
Conversion feature of convertible debentures (note 8)	374	498
Contributed surplus (note 13)	20,371	21,234
Accumulated other comprehensive loss (note 11)	(3,899)	–
Deficit	(300,780)	(224,314)
	1,011,997	927,327
	$ 1,884,005	$ 1,812,333

Commitments and contingencies (note 19)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Gregory K. Melchin
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Years Ended December 31 *(thousands of Canadian dollars, except per unit amounts)*	2009	2008
Revenue		
Petroleum and natural gas	$ 789,820	$ 1,159,718
Royalties	(130,715)	(207,522)
Gain on financial derivative contracts (note 18)	26,008	59,816
	685,113	1,012,012
Expenses		
Operating	163,250	172,471
Transportation and blending	159,354	218,706
General and administrative	35,006	29,603
Unit-based compensation (note 13)	6,443	7,812
Interest (note 16)	32,685	32,512
Financing charges (note 16)	5,496	450
Foreign exchange (gain) loss (note 17)	(22,824)	37,746
Depletion, depreciation and accretion	237,216	223,900
	616,626	723,200
Income before income taxes and non-controlling interest	68,487	288,812
Income tax expense (recovery) (note 15)		
Current	11,370	10,177
Future	(30,457)	15,383
	(19,087)	25,560
Income before non-controlling interest	87,574	263,252
Non-controlling interest (note 12)	–	(3,358)
Net income	$ 87,574	$ 259,894
Other comprehensive loss		
Foreign currency translation adjustment (note 11)	(3,899)	–
Comprehensive income	$ 83,675	$ 259,894
Net income per trust unit (note 14)		
Basic	$ 0.83	$ 2.83
Diluted	$ 0.82	$ 2.74
Weighted average trust units (note 14)		
Basic	104,894	91,683
Diluted	107,246	96,391

CONSOLIDATED STATEMENTS OF DEFICIT

Years Ended December 31 *(thousands of Canadian dollars)*	2009	2008
Deficit, beginning of year	$ (224,314)	$ (239,727)
Net income	87,574	259,894
Distributions to unitholders	(164,040)	(244,481)
Deficit, end of year	$ (300,780)	$ (224,314)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31	2009	2008
(thousands of Canadian dollars)		
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 87,574	$ 259,894
Items not affecting cash:		
Unit-based compensation (note 13)	6,443	7,812
Unrealized foreign exchange (gain) loss	(2,623)	41,712
Depletion, depreciation and accretion	237,216	223,900
Accretion on debentures and notes (notes 7 & 8)	2,908	1,681
Unrealized loss (gain) on financial derivative contracts (note 18)	54,810	(119,917)
Future income tax expense (recovery) (note 15)	(30,457)	15,383
Non-controlling interest (note 12)	–	3,358
Realized foreign exchange gain on redemption of long-term debt (notes 7 & 17)	(23,685)	–
	332,186	433,823
Change in non-cash working capital (note 17)	(27,878)	38,857
Asset retirement expenditures (note 9)	(1,146)	(1,443)
	303,162	471,237
Financing activities		
Payments of distributions	(136,409)	(194,728)
Increase (decrease) in bank loan	64,181	(33,236)
Redemption of long-term debt (note 7)	(196,411)	–
Issuance of long-term debt (note 7)	150,000	–
Issuance of trust units (note 10)	135,581	10,502
Issuance costs (note 10)	(6,101)	–
	10,841	(217,462)
Investing activities		
Petroleum and natural gas property expenditures	(164,094)	(185,083)
Acquisition of petroleum and natural gas properties, net	(133,077)	(88,566)
Change in non-cash working capital (note 17)	(6,587)	19,874
	(303,758)	(253,775)
Impact of foreign exchange on cash balances	(68)	–
Change in cash	10,177	–
Cash, beginning of year	–	–
Cash, end of year	$ 10,177	$ –

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Pursuant to the Plan of Arrangement, the Company became a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described in note 2.

The significant differences between Canadian and United States GAAP ("U.S. GAAP"), as applicable to these consolidated financial statements and notes, are described in note 21.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Goodwill impairment tests involve estimates of the Trust's fair value of the net identifiable assets and liabilities annually. If the fair value is less than the book value, an impairment would be recorded. Fair value of the Trust's net identifiable assets and liabilities are based on external market value and reserve estimates and the related future cash flows which are subject to measurement uncertainty.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments which have an initial maturity date at acquisition of not more than 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test ("ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the estimated undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such estimated undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the estimated future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the Trust. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied fair value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. The debt portion will accrete up to the principal balance at maturity. The accretion and the

interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity is reclassified to unitholders' capital along with the principal amounts converted.

Asset Retirement Obligations

The Trust recognizes a liability at the discounted value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The present value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of income and comprehensive income. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

Transactions completed in foreign currencies are reflected in Canadian dollars at the foreign currency exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in foreign currencies are reflected in the financial statements at the Canadian equivalent at the rate of exchange prevailing at the balance sheet date. Gains and losses are included in earnings.

The foreign operations are considered to be "self-sustaining operations". As a result, the revenues and expenses are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in unitholders' equity.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser at the pipeline delivery point.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, into one of the following five categories: held-for-trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. The Trust has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash is classified as held-for-trading and is measured at fair value which equals the carrying value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures are classified as other financial liabilities. Upon issuance, the convertible debentures were classified into equity and financial liability components on the balance sheet at their fair value. The financial liability, net of issuance costs, is accreted, which is included within interest expense over the maturity of the debentures using the effective interest rate method.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are expensed immediately.

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Trust are related to underlying financial instruments or future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. These instruments are classified as "held-for-trading" unless designated for hedge accounting. For derivative instruments that do not qualify as hedges or are not designated as hedges, the Trust applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizes changes in the fair value of the instrument in the statement of Income and comprehensive income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts.

The Trust has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments. This documentation specifically ties the derivative instruments to their use and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. When specific financial instruments are executed, the Trust assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in a particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Future Income Taxes

The Trust follows the liability method of accounting for taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and tax bases of an asset or liability, using substantively enacted tax rates. Future income tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 13. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Trust were presented as a non-controlling interest on the consolidated balance sheet because they failed to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference

between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the year.

3. CHANGES IN ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 20, 2009, the Trust adopted the following new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA") during 2009: Section 3064 "Goodwill and Intangible Assets" and EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". EIC-173 was adopted retrospectively without restatement of prior periods.

Goodwill and Intangible Assets

Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to their initial recognition. The adoption of this new standard did not have a material impact on the consolidated financial statements of the Trust.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

EIC-173 provides guidance on how to take into account the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 did not have a material impact on the consolidated financial statements of the Trust.

Financial Instruments – Disclosures

In June 2009, the CICA amended Section 3862 "Financial Instruments – Disclosures" to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Refer to note 18 "Financial Instruments and Risk Management" for the enhanced disclosures and liquidity risk disclosures.

Financial Instruments – Recognition and Measurement

In July 2009, the CICA amended Section 3855, "Financial Instruments – Recognition and Measurement", in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and provided that certain conditions have been met, permit reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The adoption of this amended standard on December 31, 2009 did not have a material impact on the consolidated financial statements of the Trust.

Change in Foreign Currency Translation

The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date (0.9555 USD/CAD), while revenues and expenses are translated using the average exchange rate for the period (0.8760 USD/CAD). Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity and are recognized in net income when there has been a reduction in net investment.

Previously, foreign operations were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate while other assets and liabilities were translated at the historical rate. Revenues and expenses were translated at the average monthly rate except for depletion, depreciation and accretion, which were translated on the same basis as the assets to which they relate. Translation gains and losses were included in the determination of net income for the period.

This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties.

Future Accounting Changes

Business Combinations

In January 2009, the CICA issued Section 1582 "Business Combinations" which establishes principles and requirements of the acquisition method for business combinations and related disclosures. The purchase price is to be based on trading data at the closing date of the acquisition, not the announcement date of the acquisition, and most acquisition costs are to be expensed as incurred. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting for future business combinations.

Consolidated Financial Statements

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" which establishes standards for the preparation of consolidated financial statements and Section 1602 "Non-controlling Interests" which provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The Trust plans to adopt these standards prospectively effective January 1, 2011. The adoption of these standards may have an impact on the Trust's accounting for future business combinations.

4. CORPORATE ACQUISITIONS

On June 4, 2008, Baytex acquired all the issued and outstanding shares of Burmis Energy Inc., a public company which had interests in certain natural gas and light oil properties located primarily in west central Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 4, 2008. In conjunction with the acquisition, Burmis Energy Inc. was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	3,934
Total purchase price	$ 180,467
Allocation of purchase price:	
Property, plant and equipment	$ 219,913
Future income taxes	(37,910)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 180,467

All of the issued and outstanding shares of Burmis were acquired on the basis of 0.1525 of a Baytex trust unit for each Burmis share, resulting in the issuance of 6,383,416 Baytex trust units valued at $23.82 per unit, which was the average closing price of Baytex trust units for the ten trading days bordering the initial public announcement of the transaction.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31	
	2009	2008
Petroleum and natural gas properties	**$ 3,943,850**	$ 3,648,431
Accumulated depletion and depreciation	**(2,280,098)**	(2,047,414)
	$ 1,663,752	$ 1,601,017

In calculating the Canadian cost centre depletion and depreciation provision for 2009, $47.7 million (2008 – $63.6 million) of costs relating to undeveloped properties were excluded, while $538.3 million (2008 – $385.0 million) of future development costs were included for the calculation. In calculating the U.S. cost centre depletion and depreciation provision for 2009, $77.0 million (2008 – $57.6 million) of costs relating to undeveloped properties were excluded, while $77.3 million (2008 – $56.3 million) of future development costs were included for the calculation. No general and administrative expenses have been capitalized since the inception of operations as a trust.

Depletion and depreciation expense related to the Canadian and U.S. cost centres in 2009 were $228.8 million and $4.2 million respectively (2008 – $218.4 million and $1.7 million).

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2009 using the following benchmark reference prices for the years 2010 to 2014 adjusted for commodity differentials specific to the Trust:

	2010	2011	2012	2013	2014
WTI crude oil (US$/bbl)	79.17	84.46	86.89	90.20	92.01
AECO natural gas ($/MMBtu)	5.36	6.21	6.44	7.23	7.98
Exchange rate (USD/CAD)	0.92	0.92	0.92	0.92	0.92

The prices and costs subsequent to 2014 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculations, the Trust's estimated undiscounted future net cash flows associated with proved reserves plus the cost less impairment of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. In June 2009, total credit facilities were increased to $515 million from $485 million. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. The credit facilities mature on June 30, 2010 and are eligible for extension. At December 31, 2009 a total of $265.1 million was drawn under the credit facilities (December 31, 2008 – $208.5 million).

7. LONG-TERM DEBT

	December 31, 2009	December 31, 2008
9.15% senior unsecured debentures	$ 150,000	$ –
10.5% senior subordinated notes (US$247)	–	303
9.625% senior subordinated notes (US$179,699)	–	220,059
	150,000	220,362
Discontinued fair value hedge	–	(3,089)
	$ 150,000	$ 217,273

On August 26, 2009, the Trust issued $150.0 million Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. These debentures are unsecured and are subordinate to the Company's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Trust's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525%, and 2015 at 100%.

On September 25, 2009, the Company redeemed all of the 9.625% senior subordinated notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% senior subordinated notes due February 15, 2011 (principal amount US$0.2 million) for an aggregate redemption price of $196.4 million. These notes were unsecured and were subordinate to the Company's bank credit facilities. These notes were carried at amortized cost, net of a discontinued fair value hedge. The notes accrete up to the principal balance at maturity using the effective interest method.

The Company recorded accretion expense of $2.8 million for the year ended December 31, 2009 (2008 – $1.6 million). The effective interest rate applied was 10.6%. The discontinued fair value hedge has been recognized in accretion expense upon redemption of the senior subordinated notes.

8. CONVERTIBLE DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	–	97	–
Balance, December 31, 2008	10,398	$ 10,195	$ 498
Conversion	(2,583)	(2,544)	(124)
Accretion	–	85	–
Balance, December 31, 2009	7,815	$ 7,736	$ 374

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully-paid trust units at a conversion price of $14.75 per trust unit. At December 31, 2009, the debentures are classified as a current liability as they mature and are due and payable on December 31, 2010.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

9. ASSET RETIREMENT OBLIGATIONS

	December 31, 2009	December 31, 2008
Balance, beginning of year	**$ 49,351**	$ 45,113
Liabilities incurred	**1,320**	871
Liabilities settled	**(1,146)**	(1,443)
Acquisition of liabilities	**3,268**	1,536
Disposition of liabilities	**(146)**	(904)
Accretion	**4,184**	3,802
Change in estimate[1]	**(2,212)**	376
Foreign exchange	**(26)**	–
Balance, end of year	**$ 54,593**	$ 49,351

(1) Changes in the status of wells and changes in the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2009 is $279.3 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 2.0%.

10. UNITHOLDERS' CAPITAL

The Trust is authorized to issue an unlimited number of trust units.

	Number of units	Amount
Balance, December 31, 2007	84,540	$ 821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of unit rights	1,386	10,653
Transfer from contributed surplus on exercise of unit rights	–	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	97,685	$ 1,129,909
Issued for cash	7,935	115,058
Issuance costs, net of income tax	–	(5,072)
Issued on conversion of debentures	175	2,667
Issued on exercise of unit rights	2,059	20,523
Transfer from contributed surplus on exercise of unit rights	–	7,306
Issued pursuant to distribution reinvestment plan	1,445	25,540
Balance, December 31, 2009	**109,299**	**$ 1,295,931**

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 90 percent of the "market price" of the trust units on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $250,000 per month. Redemptions in excess of the cash limit, if not waived by the Trust, shall be satisfied by distribution of subordinate, unsecured redemption notes bearing interest at 12% per annum, due and payable no later than September 1, 2033.

11. ACCUMULATED OTHER COMPREHENSIVE LOSS

	December 31, 2009	December 31, 2008
Balance, beginning of year	**$ –**	$ –
Foreign currency translation adjustment	**(3,899)**	–
Balance, end of year	**$ (3,899)**	$ –

Accumulated other comprehensive loss is composed entirely of currency translation adjustments on the foreign operations. The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties.

12. NON-CONTROLLING INTEREST

On May 30, 2008, the Trust announced that the Company had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for trust units in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2009, and December 31, 2008, there were no exchangeable shares outstanding.

The exchangeable shares of the Company were presented as a non-controlling interest on the consolidated balance sheet because they failed to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income had been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	–	3,358
Balance, December 31, 2008 and 2009	–	$ –

13. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of unit rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Plan. Under the Plan, unit rights have a maximum term of five years and vest and become exercisable as to one-third on each of the first, second and third anniversaries of the grant date. The Plan provides that the exercise price of the unit rights may be reduced to account for future distributions, subject to certain performance criteria. Effective November 16, 2009, the Plan was amended to (i) base the exercise price of unit rights on the closing price of the trust units on the trading day prior to the date of grant (previously based on a five-day volume weighted average trading price) and (ii) permit the granting of unit rights with a fixed exercise price.

The Trust recorded compensation expense of $6.4 million for the year ended December 31, 2009 (year ended December 31, 2008 – $7.8 million) related to the unit rights granted under the Plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $6.38 per unit for unit rights issued during the year ended December 31, 2009 ($2.42 per unit for the year ended December 31, 2008). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2009	2008
Expected annual exercise price reduction (on rights with declining exercise price)	**$1.44 – $2.16**	$2.16 – $3.00
Expected volatility	**39% – 43%**	28% – 39%
Risk-free interest rate	**1.78% – 2.72%**	2.98% – 4.17%
Expected life of unit rights (years)(1)	**Various**	Various

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Plan.

The number of unit rights outstanding and exercise prices are detailed below:

	Number of unit rights	Weighted average exercise price[1]
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	8,449	$ 14.58
Granted	1,844	$ 24.87
Exercised	(2,059)	$ 9.97
Cancelled	(114)	$ 16.43
Balance, December 31, 2009	8,120	$ 16.68

(1) *Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.*

The following table summarizes information about the unit rights outstanding at December 31, 2009:

Range of Exercise Prices	**Number Outstanding at December 31, 2009**	Weighted Average Remaining Term *(years)*	Weighted Average Exercise Price	**Number Exercisable at December 31, 2009**	Weighted Average Exercise Price
$ 2.93 to $ 8.00	**814**	0.8	$ 6.15	**814**	$ 6.15
$ 8.01 to $13.00	**201**	1.3	$ 9.34	**180**	$ 9.06
$13.01 to $18.00	**5,371**	3.0	$ 15.53	**2,944**	$ 15.39
$18.01 to $23.00	**372**	3.8	$ 21.04	**–**	$ 18.15
$23.01 to $27.72	**1,362**	4.9	$ 27.42	**10**	$ 24.89
$ 2.93 to $27.72	**8,120**	3.1	$ 16.68	**3,948**	$ 13.22

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2007	$ 18,527
Compensation expense	7,812
Transfer from contributed surplus on exercise of unit rights[1]	(5,105)
Balance, December 31, 2008	$ 21,234
Compensation expense	6,443
Transfer from contributed surplus on exercise of unit rights[1]	(7,306)
Balance, December 31, 2009	$ 20,371

(1) *Upon exercise of unit rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.*

14. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, converted at the year end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	December 31, 2009			December 31, 2008		
	Net income	Trust units	Net income per unit	Net income	Trust units	Net income per unit
Net income per basic unit	$ 87,574	104,894	$ 0.83	$ 259,894	91,683	$ 2.83
Dilutive effect of unit rights	–	1,697		–	2,955	
Conversion of convertible debentures	502	655		654	882	
Exchange of exchangeable shares	–	–		3,358	871	
Net income per diluted unit	$ 88,076	107,246	$ 0.82	$ 263,906	96,391	$ 2.74

For the year ended December 31, 2009, 1.6 million unit rights (year ended December 31, 2008 – 45,000) were excluded in calculating the weighted average number of diluted trust units outstanding as they were anti-dilutive.

15. INCOME TAXES

The provision for (recovery of) income taxes has been computed as follows:

	Years Ended December 31	
	2009	2008
Income before income taxes and non-controlling interest	$ 68,487	$ 288,812
Expected income taxes at the statutory rate of 29.48% (2008 – 30.22%)	20,190	87,279
Increase (decrease) in income taxes resulting from:		
Net income of the Trust	(50,474)	(79,930)
Non-taxable portion of foreign exchange (gain) loss	(2,994)	6,204
Effect of change in income tax rate	601	(1,402)
Effect of change in opening tax pool balances	5,501	878
Effect of change in valuation allowance	(5,374)	–
Unit-based compensation	1,899	2,361
Other	194	(7)
Future income tax (recovery) expense	(30,457)	15,383
Current income tax expense	11,370	10,177
Income tax (recovery) expense	$ (19,087)	$ 25,560

The components of the net future income tax liability are as follows:

	As at December 31	
	2009	2008
Future income tax liabilities:		
Petroleum and natural gas properties	$ 200,820	$ 197,694
Financial derivative contracts	9,432	25,358
Other	5,438	14,215
Future income tax assets:		
Asset retirement obligations	(13,929)	(12,652)
Non-capital loss carry-forward	(13,185)	(11,813)
Valuation allowance on non-capital losses	–	4,967
Financial derivative contracts	(1,789)	–
Other	(220)	–
Net future income tax liability(1)	186,567	217,769
Current portion of net future income tax liability	7,312	25,358
Long-term portion of net future income tax liability	$ 179,255	$ 192,411

(1) Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken totaled $48.4 million ($42.9 million in 2008) and expire from 2014 to 2028.

16. INTEREST EXPENSE AND FINANCING CHARGES

The Trust incurred interest expense and financing charges on its outstanding debts as follows:

	Years Ended December 31	
	2009	2008
Bank loan and other	$ 9,394	$ 12,235
Long-term debt	22,578	19,332
Convertible debentures	713	945
Financing charges	5,496	450
Interest expense and financing charges	$ 38,181	$ 32,962

17. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	2009	2008
Current assets	$ (50,655)	$ 35,460
Current liabilities	16,140	23,271
Foreign exchange	50	–
	$ (34,465)	$ 58,731
Changes in non-cash working capital related to:		
Operating activities	$ (27,878)	$ 38,857
Investing activities	(6,587)	19,874
	$ (34,465)	$ 58,731

Supplemental Cash Flow Information

During the year the Trust made the following cash outlays in respect of interest, financing charges and current income taxes paid:

	Years Ended December 31	
	2009	2008
Interest paid	$ 33,002	$ 30,205
Financing charges paid	$ 5,278	$ 450
Current income taxes paid	$ 10,534	$ 9,972

Foreign Exchange (Gain) Loss

	Years Ended December 31	
	2009	2008
Unrealized foreign exchange (gain) loss	$ (2,623)	$ 41,712
Realized foreign exchange (gain)(1)	(20,201)	(3,966)
Foreign exchange (gain) loss	$ (22,824)	$ 37,746

(1) *The retirement of the US$ senior subordinated notes on September 25, 2009 resulted in a realized gain of $51.0 million. Only $23.7 million of this gain is recognized in the twelve months ended December 31, 2009 as $27.3 million was reported in prior periods as an unrealized foreign exchange gain through the translation process at each period end.*

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial derivative contracts, long-term debt and convertible debentures.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following five categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Held for trading				
Cash	$ 10,177	$ 10,177	$ –	$ –
Derivatives designated as held for trading	31,994	31,994	85,678	85,678
Total held for trading	$ 42,171	$ 42,171	$ 85,678	$ 85,678
Loans and receivables				
Accounts receivable	$ 137,154	$ 137,154	$ 87,551	$ 87,551
Total loans and receivables	$ 137,154	$ 137,154	$ 87,551	$ 87,551
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	$ (6,068)	$ (6,068)	$ –	$ –
Total held for trading	$ (6,068)	$ (6,068)	$ –	$ –
Other financial liabilities				
Accounts payable and accrued liabilities	$ (180,493)	$ (180,493)	$ (164,353)	$ (164,353)
Distributions payable to unitholders	(19,674)	(19,674)	(17,583)	(17,583)
Bank loan	(265,088)	(265,088)	(208,482)	(208,482)
Long-term debt	(150,000)	(162,750)	(217,273)	(200,557)
Convertible debentures	(7,736)	(15,474)	(10,195)	(9,837)
Total other financial liabilities	$ (622,991)	$ (643,479)	$ (617,886)	$ (600,812)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than long-term debt and convertible debentures, are equal to their book amounts due to the short-term maturity of these instruments. The

fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long-term debt is based on the lower of trading value and the present value of future cash flows associated with the convertible debentures. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows plus the conversion option associated with the convertible debentures. The Trust expenses all financial instrument transaction costs immediately.

Fair Value of Derivatives

The Trust classifies the fair value of derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The following table presents the Trust's fair value hierarchy for those assets and liabilities measured at fair value on a recurring basis as of December 31, 2009. The fair value measurement of financial derivative contracts related to the Trust's foreign currency swaps, interest rate swaps and commodity price collars are considered Level 2.

As at December 31, 2009	Level 1	Level 2	Level 3	Total
Derivatives designated as held for trading	–	$ 25,926	–	$ 25,926

Financial Risk

The Trust is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk

The Trust is exposed to fluctuations in foreign currency as a result of the U.S. dollar portion of its bank loan, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Trust's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of currency exchange rate fluctuations, the Trust may enter into agreements to fix the Canada – U.S. exchange rate.

At December 31, 2009, the Trust had in place the following currency contracts:

Type	Period	Amount per month	Sales Price(1)
Forward sales	October 1, 2009 to December 31, 2010	US$ 1.0 million	1.0870
Forward sales	January 1, 2010 to December 31, 2010	US$10.0 million	1.1889
Forward sales	January 1, 2010 to March 31, 2011	US$ 5.0 million	1.1500
Forward sales	January 1, 2010 to December 31, 2011	US$ 5.0 million	1.0711

(1) Based on the weighted average exchange rate (CAD/USD).

The following table demonstrates the effect of movements in the Canada-United States exchange rate on net income before income taxes due to changes in the fair value of the currency swaps as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2009.

	$0.01 Increase (Decrease) in CAD/USD Exchange Rate
Loss (gain) on currency forward sales agreements	$ 3,060
Loss (gain) on other monetary assets/liabilities	1,565
Impact on income before income taxes and other comprehensive income	$ 4,625

The carrying amounts of the Trust's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
U.S. dollar denominated	**US$ 67,389**	US$ 84,070	**US$ 198,690**	US$ 191,571

Subsequent to December 31, 2009, the Trust added the following currency contract:

Type	Period	Amount per month	Sales Price[1]
Forward sales	January 1, 2011 to December 31, 2011	US$ 3.0 million	1.0647

(1) Based on the weighted average exchange rate (CAD/USD).

Interest rate risk

The Trust's interest rate risk arises from its floating rate bank credit facilities. As at December 31, 2009, $265.1 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 100 basis points in interest rates would impact net income before taxes for the year ended December 31, 2009 by approximately $2.0 million. The Trust uses a combination of short-term and long-term debt to finance operations. Short-term debt is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

At December 31, 2009, the Trust had the following interest swap financial derivative contracts:

Type	Period	Amount per month	Fixed interest rate	Floating rate index
Swap – pay floating, receive fixed	September 23, 2009 to August 26, 2011	Cdn$150.0 million	9.15%	3 month BA plus 7.875%
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3 month LIBOR
Swap – pay fixed, receive floating	September 25, 2012 to September 25, 2014	US$90.0 million	4.39%	3 month LIBOR

When assessing the potential impact of forward interest rate changes, an increase or decrease of 100 basis points would result in an increase or decrease, respectively, to the unrealized gain of $2.0 million relating to financial derivative instruments outstanding as at December 31, 2009.

Commodity Price Risk

The Trust monitors and, when appropriate, utilizes financial derivative agreements or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of the Company. Under the Trust's risk management policy, financial derivatives are not to be used for speculative purposes.

When assessing the potential impact of oil price changes on the financial derivative instruments outstanding as at December 31, 2009, a 10% increase would result in a reduction to the unrealized gain as at December 31, 2009 of $16.5 million, while a 10% decrease would result in an increase to the unrealized gain as at December 31, 2009 of $18.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative instruments outstanding as at December 31, 2009, a 10% increase would result in a reduction to the unrealized gain as at December 31, 2009 of $2.9 million, while a 10% decrease would result in an increase to the unrealized gain as at December 31, 2009 of $3.9 million.

Financial Derivative Agreements

At December 31, 2009, the Trust had the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Buy	Calendar 2010	575 bbl/d	US$64.00	WTI
Fixed – Sell	Calendar 2010	1,200 bbl/d	US$77.78	WTI
Collar – Sell	Calendar 2010	2,000 bbl/d	US$70.00 – 95.65	WTI
Collar – Sell	Calendar 2010	1,000 bbl/d	US$75.00 – 87.60	WTI
Fixed – Sell	Calendar 2010	1,000 bbl/d	US$83.10	WTI
Fixed – Sell	Calendar 2010	770 bbl/d	US$82.30	WTI
Fixed – Sell	Calendar 2010	1,000 bbl/d	US$80.08	WTI

Natural Gas	Period	Volume	Price/Unit	Index
Fixed – Sell	January to February 2010	10,000 MMBtu/d	US$5.63 – 5.66	NYMEX
Fixed – Sell	January to April 2010	3,000 GJ/d	Cdn$4.54	AECO
Fixed – Sell	March 2010	2,500 MMBtu/d	US$4.78	NYMEX
Fixed – Buy	March 2010	2,500 MMBtu/d	US$5.83	NYMEX
Collar – Sell	April 2009 to December 2010	5,000 GJ/d	Cdn$5.00 – 6.30	AECO
Fixed – Sell	May 2010	2,500 MMBtu/d	US$5.79	NYMEX
Collar – Sell	Calendar 2010	1,000 GJ/d	Cdn$5.50 – 7.00	AECO
Fixed – Sell	Calendar 2010	3,000 GJ/d	Cdn$6.19	AECO
Fixed – Sell	Calendar 2010	2,000 GJ/d	Cdn$5.05	AECO
Fixed – Sell	Calendar 2010	2,000 GJ/d	Cdn$5.05	AECO
Sold call	January to February 2011	15,000 MMBtu/d	US$7.00	NYMEX
Sold call	January to March 2011	5,000 MMBtu/d	US$6.60	NYMEX
Fixed – Buy	April 2011	2,500 MMBtu/d	US$5.97	NYMEX

The financial derivative contracts are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income and comprehensive income:

	Years Ended December 31	
	2009	2008
Realized gain (loss) on financial derivative contracts	**$ 80,818**	$ (60,101)
Unrealized (loss) gain on financial instruments	**(54,810)**	119,917
Gain on financial derivative contracts	**$ 26,008**	$ 59,816

Subsequent to December 31, 2009, the Trust added the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Sell	February to December 2010	1,000 bbl/d	US$85.50	WTI

Natural Gas	Period	Volume	Price/Unit	Index
Sold call	March 2011	3,000 MMBtu/d	US$6.25	NYMEX
Sold call	July to December 2011	3,000 MMBtu/d	US$6.25	NYMEX

Physical Delivery Contracts

At December 31, 2009, the Trust had the following physical delivery contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
WCS Blend	January to June 2010	1,500 bbl/d	WTI less US$10.75
WCS Blend	January to June 2010	1,500 bbl/d	WTI × 84.50%
WCS Blend	January to June 2010	1,000 bbl/d	WTI less US$12.45
WCS Blend	January to June 2010	1,000 bbl/d	WTI × 83.12%
LLK Blend	February to September 2010	500 bbl/d	WTI less US$10.25
LLK Blend	February to September 2010	500 bbl/d	WTI × 86.85%
WCS Blend	July to December 2010	1,000 bbl/d	WTI less US$14.08
WCS Blend	July to December 2010	1,000 bbl/d	WTI × 81.06%
WCS Blend	July to December 2010	500 bbl/d	WTI less US$13.15
WCS Blend	Calendar 2010	2,500 bbl/d	US$51.04
Condensate	Calendar 2010	575 bbl/d	WTI plus US$2.25 – 2.60
WCS Blend	Calendar 2010	1,500 bbl/d	WTI less US$14.50
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.74
WCS Blend	Calendar 2010	1,000 bbl/d	WTI × 83.27%
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.50
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.25
WCS Blend	Calendar 2010	1,000 bbl/d	WTI × 84.00%
WCS Blend	Calendar 2010	500 bbl/d	WTI × 84.00%
WCS Blend	Calendar 2010	500 bbl/d	WTI less US$13.29
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.00

Natural Gas	Period	Volume	Price/Unit
Price collar	Calendar 2010	5,000 GJ/d	AECO Cdn$5.00 – 6.28
Price collar	Calendar 2011	2,500 GJ/d	AECO Cdn$5.50 – 7.10

Subsequent to December 31, 2009, the Trust added the following physical delivery contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
LLB Blend	April to June 2010	500 bbl/d	WTI less US$10.00
LLB Blend	April to June 2010	500 bbl/d	WTI × 87.40%
LLB Blend	July to September 2010	500 bbl/d	WTI less US$10.25
LLB Blend	July to September 2010	500 bbl/d	WTI × 87.20%

Natural Gas	Period	Volume	Price/Unit
Fixed – Sell	February to November 2011	2500 GJ/d	AECO Cdn$5.03

Liquidity Risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional trust units. As at

December 31, 2009, the Trust had available unused bank credit facilities in the amount of $198 million, net of working capital deficiency.

The timing of cash outflows (excluding interest) relating to financial liabilities is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	$ 180,493	$ 180,493	$ –	$ –	$ –
Distributions payable to unitholders	19,674	19,674	–	–	–
Bank loan[1]	265,088	265,088	–	–	–
Long-term debt[2]	150,000	–	–	–	150,000
Convertible debentures[2]	7,815	7,815	–	–	–
	$ 623,070	$ 473,070	$ –	$ –	$ 150,000

(1) The bank loan is a 364-day revolving loan with the ability to extend the term.
(2) Principal amount of instruments.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only creditworthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at December 31, 2009, accounts receivable included an $8.5 million balance over 90 days (December 31, 2008 – $9.9 million), of which $2.7 million pertains to drilling credits receivable from the Alberta Minister of Finance. A balance of $2.3 million (December 31, 2008 – $2.4 million) has been set up as allowance for doubtful accounts.

19. COMMITMENTS AND CONTINGENCIES

At December 31, 2009, the Trust had operating leases and processing and transportation obligations as summarized below:

	Total	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Beyond 5 years
Operating leases	$ 40,014	$ 3,408	$ 3,838	$ 3,821	$ 3,684	$ 3,815	$ 21,448
Processing and transportation agreements	7,708	4,328	2,949	302	100	29	–
Total	$ 47,722	$ 7,736	$ 6,787	$ 4,123	$ 3,784	$ 3,844	$ 21,448

At December 31, 2009, the Trust had the following power contracts:

Power	Period	Volume	Price/Unit
Fixed – Buy	March 2009 to June 30, 2010	0.6 MW/hr	Cdn$76.89
Fixed – Buy	Calendar 2010	0.1 MW/hr	Cdn$49.43
Fixed – Buy	Calendar 2010	0.2 MW/hr	Cdn$48.93

Subsequent to December 31, 2009 the Trust added the following power contracts:

Power	Period	Volume	Weighted Average Price/Unit
Fixed – Buy	February to June 2010	0.1 MW/hr	Cdn$44.22
Fixed – Buy	June to December 2010	0.2 MW/hr	Cdn$49.11
Fixed – Buy	June to December 2010	0.2 MW/hr	Cdn$50.33
Fixed – Buy	January to December 2011	0.2 MW/hr	Cdn$47.71

Other

During 2009, the Company implemented an Income Tracking Unit ("ITU") Plan. Liabilities incurred under this plan are settled in cash on predetermined dates, contingent upon attainment of prescribed payment conditions, including the participant's service status with the Company and the intrinsic value of reference incentive rights. Liabilities are recorded when the likelihood of the prescribed payment conditions being met can be reasonably estimated. At December 31, 2009, a $0.1 million liability was accrued.

At December 31, 2009, there were no outstanding letters of credit. At December 31, 2008 there were outstanding letters of credit aggregating $2.3 million issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, the Company became liable for contingent consideration whereby an additional amount would be payable by the Company if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase; therefore, such consideration is recognized only when the contingency is resolved. As at December 31, 2009, additional payments totaling $7.2 million have been paid under the agreement and recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement; therefore, no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

20. CAPITAL DISCLOSURES

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP measure which is the sum of monetary working capital (being current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative contracts gains or losses)), the principal amount of long-term debt and the balance sheet value of the convertible debentures. At December 31, 2009, total net monetary debt was $474.3 million.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new trust units or debt, or sell assets to reduce debt.

The Trust monitors capital based on the current and projected ratio of total monetary debt to funds from operations and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to funds from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to funds from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to funds from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its funds from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank credit facilities, senior subordinated debentures and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbour amount. The safe harbour amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbour amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. The safe harbour amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth.

On December 4, 2008, the Minister of Finance announced changes to the Guidelines to allow an income trust to accelerate the utilization of the safe harbour amounts for each of 2009 and 2010 so that the safe harbour amounts for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for an income trust, but it allows an income trust to use its safe harbour amount remaining as of December 4, 2008 in a single year, rather than staging a portion of the safe harbour amount over the 2009 and 2010 years.

For the Trust, the safe harbour amounts were approximately $730 million for 2006/2007 and approximately $365 million for each of the subsequent three years with any unused amount carrying forward to the next year. The Trust did not issue equity in excess of its safe harbour amounts during 2006, 2007, 2008 or 2009. The Trust issued $165.9 million in equity during the year ended December 31, 2009, resulting in an unused available safe harbour amount of $1,160.7 million as at December 31, 2009. The Trust is planning to complete a conversion transaction from the current trust structure to a corporate legal form to be completed before the end of 2010.

21. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The significant differences between Canadian and United States GAAP ("U.S. GAAP"), as applicable to these consolidated financial statements and notes, are described below. In addition to the significant differences described within, presentation of the following additional disclosures are required under U.S. GAAP and Regulation S-X of the United States Securities and Exchange Commission ("SEC") or specified in Item 18 of the Form 20-F.

Reconciliation of Net Income under Canadian GAAP to U.S. GAAP

	Note	Years Ended December 31 2009	2008
Net income – Canadian GAAP		$ 87,574	$ 259,894
Increase (decrease) under U.S. GAAP:			
Depletion, depreciation and accretion	A,B	72,721	(695,715)
Interest, net	M,D	3,174	959
Financing charges	B	3,631	–
Unit-based compensation	J	(92,627)	(1,206)
Income tax (expense) recovery	K	(34,541)	160,235
Non-controlling interest	G	–	3,358
Net income (loss) – U.S. GAAP		$ 39,932	$ (272,475)
Net income (loss) per trust unit	O		
Basic		$ 0.38	$ (2.94)
Diluted		$ 0.38	$ (2.94)
Weighted average trust units	O		
Basic		104,894	92,554
Diluted		106,419	92,554

Condensed Consolidated Statements of Operations – U.S. GAAP

	Note	Years Ended December 31 2009	2008
Revenue			
Petroleum and natural gas sales, net of royalties	L	$ 659,105	$ 952,196
Gain on financial derivative contracts	C	26,008	59,816
		685,113	1,012,012
Expenses			
Operating	J	176,706	174,445
Transportation and blending		159,354	218,706
General and administrative	J	120,620	36,647
Interest	M	29,511	31,553
Financing charges	B	1,865	450
Foreign exchange (gain) loss		(22,824)	37,746
Depletion, depreciation and accretion	A,B	164,495	919,615
		629,727	1,419,162
Income (loss) before taxes		55,386	(407,150)
Income tax expense (recovery)			
Current		11,370	10,177
Future	K	4,084	(144,852)
		15,454	(134,675)
Net income (loss)		39,932	(272,475)
Other comprehensive loss			
Foreign currency translation adjustment	I	(3,951)	–
Comprehensive income (loss)		$ 35,981	$ (272,475)

Consolidated Statements of Accumulated Deficit

		2009	2008
Deficit, beginning of the year		$ (1,206,793)	$(1,159,401)
Net income (loss)		39,932	(272,475)
Distributions to unitholders	H	(164,040)	(244,481)
Adjustment for fair value of temporary equity	G	(1,302,397)	469,564
Deficit, end of the year		$ (2,633,298)	$(1,206,793)

Condensed Consolidated Balance Sheets – U.S. GAAP

		As at December 31			
		2009		2008	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets	C,Q	$ 179,539	$ 179,539	$ 173,561	$ 173,561
Future income tax asset	K	418	418	–	–
Financial derivative contracts	C	2,541	2,541	–	–
Petroleum and natural gas properties	A,E	3,943,850	3,843,644	3,648,431	3,548,224
Accumulated depletion & depreciation	A	(2,280,098)	(3,002,832)	(2,047,414)	(2,844,948)
Petroleum and natural gas properties, net		1,663,752	840,812	1,601,017	703,276
Deferred charges	B	–	3,501	–	2,059
Future income tax asset	K	–	4,338	–	–
Goodwill		37,755	37,755	37,755	37,755
		$ 1,884,005	$ 1,068,904	$ 1,812,333	$ 916,651
Liabilities and Unitholders' Equity					
Current liabilities	C,D,F,Q	$ 486,324	$ 486,403	$ 415,776	$ 390,418
Long-term debt		150,000	150,000	217,273	220,362
Convertible debentures	D	–	–	10,195	10,398
Asset retirement obligations		54,593	54,593	49,351	49,351
Share-based payment liability	J	–	91,430	–	21,825
Future income tax liability	A,E,K	179,673	749	192,411	–
Financial derivative contracts		1,418	1,418	–	–
		$ 872,008	$ 784,593	$ 885,006	$ 692,354
Temporary equity	G	–	2,921,560	–	1,431,090
Unitholders' capital	G,H	1,295,931	–	1,129,909	–
Conversion feature of convertible debentures	D	374	–	498	–
Contributed surplus	G,J	20,371	–	21,234	–
Accumulated other comprehensive loss	I	(3,899)	(3,951)	–	–
Deficit		(300,780)	(2,633,298)	(224,314)	(1,206,793)
		1,011,997	(2,637,249)	927,327	(1,206,793)
		$ 1,884,005	$ 1,068,904	$ 1,812,333	$ 916,651

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

	Years Ended December 31 2009	2008
Operating activities:		
Net income (loss)	$ 39,932	$ (272,475)
Unit-based compensation	99,070	9,018
Depletion, depreciation and accretion	162,329	918,770
Amortization of deferred charges	2,166	845
Unrealized foreign exchange (gain) loss	(2,889)	42,434
Unrealized loss (gain) on financial derivative contracts	54,810	(119,917)
Future income tax (recovery)	4,084	(144,852)
Realized foreign exchange gain on redemption of long-term debt	(23,685)	–
Change in non-cash working capital	(27,878)	38,857
Asset retirement expenditures	(1,146)	(1,443)
	$ 306,793	$ 471,237
Cash from (used in) financing activities	$ 7,210	$ (217,462)
Cash (used in) investing activities	$ (303,758)	$ (253,775)
Impact of foreign exchange on cash balances	$ (68)	$ –

(A) Full Cost Accounting

Under U.S. GAAP, for determining the limitation of capitalized costs, the carrying value of a cost centre's oil and gas properties cannot exceed the present value of after tax future net cash flows from proved reserves, discounted at 10%, using oil and gas prices based upon an average price in the prior 12-month period and unescalated costs, plus (i) the costs of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation, less (iii) income tax effects related to differences between the book and tax basis of the properties. The amount of the impairment expense is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost centre's petroleum and natural gas properties.

For Canadian GAAP, the carrying value includes all capitalized costs for each cost centre, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. The U.S. GAAP definition under Regulation S-X is similar to Canadian GAAP, except that under U.S. GAAP the carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

The costs of unproved properties included in the petroleum and natural gas properties on the balance sheet date December 31, 2009, which have been excluded from the depletion and ceiling test calculations, by year in which the costs were incurred:

	Total	2009	2008	Prior to 2008
Property acquisitions				
Canada	$ 47,651	$ 2,246	$ 12,003	$ 33,402
USA	76,969	40,338	36,631	–
	$ 124,620	$ 42,584	$ 48,634	$ 33,402

The costs of unproved properties are amortized into the depletion base over five years for Canadian cost centre and three years for the U.S. cost centre. There were no major development projects that were excluded from the capitalized costs being amortized.

Under Canadian GAAP, depletion is calculated by reference to proved reserves estimated using forecast prices. Under U.S. GAAP, depletion is calculated by reference to proved reserves estimated using unescalated prices. The difference in proved reserves has resulted in $81.2 million less depletion recorded under U.S. GAAP for the year ended December 31, 2009 (December 31, 2008 – $104.3 million less depletion).

At December 31, 2009, Baytex's capitalized costs of petroleum and natural gas properties in the Canadian cost centre did not exceed the full cost ceiling under U.S. GAAP. The ceiling test in the U.S. cost centre resulted in a charge of $6.3 million. At December 31, 2008, the Trust's capitalized costs of petroleum and natural gas properties exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $799.1 million charged to depletion, depreciation and accretion ($752.1 million in the Canada cost centre and $47.0 million in the U.S. cost centre). As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

(B) Deferred Charges

Under Canadian GAAP, the Trust elected to expense all financial instrument transaction costs immediately. Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. Under U.S. GAAP, transaction costs continue to be deferred and amortized over the expected term of the related financial asset or liability. Under U.S. GAAP, there is an asset of $3.5 million on the balance sheet as at December 31, 2009 (December 31, 2008 – $2.1 million). Additional amortization expense of $2.2 million has been recognized in net income (December 31, 2008 – $0.8 million) under U.S. GAAP.

(C) Financial Derivative Contracts

Under Section 3855, "Financial Instruments – Recognition and Measurement", physical commodity contracts which are entered into and continue to be held for the purposes of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements are excluded from the requirements of Section 3855 provided the price is not based on a variable that is not closely related to the asset being purchased, sold or used and they are documented as such. Upon the adoption of Section 3855 on January 1, 2007, the Canadian – U.S. GAAP difference has been eliminated and no additional financial asset or liability has been recognized for U.S. GAAP at December 31, 2009 or December 31, 2008.

The Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification ("ASC") 820 – "Fair Value Measurements and Disclosures" (formerly Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements"). This standard defines fair value, establishes a framework for measuring fair value in U.S. GAAP, and expands disclosure about fair value measurements. The Trust adopted these provisions effective January 1, 2008. In June 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", and upon the Trust's adoption, eliminated the Canadian – U.S. GAAP difference as at December 31, 2009. The implementation of these standards did not have a material impact on the consolidated financial statements.

(D) Convertible Debentures

Under Canadian GAAP, the Trust's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete the balance to the principal due on maturity.

Under U.S. GAAP, the convertible debentures in their entirety are classified as debt. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP. As a result $0.4 million has been

reclassified to liabilities from equity as at December 31, 2009 (December 31, 2008 – $0.5 million) and $0.1 million of non-cash interest expense has been reversed (December 31, 2008 – $0.1 million).

(E) Step Acquisition on Exchange of Exchangeable shares

Under Canadian GAAP, when the exchangeable shares are exchanged for Trust Units, the transaction is treated as a step acquisition whereby petroleum and natural gas properties are increased by the tax effected difference between the fair value of the exchangeable shares and their carrying value. The offset is credited to future tax liability and Trust units. Under U.S. GAAP the exchangeable shares are considered to be a component of temporary equity and therefore no business combination is considered to have occurred. The cumulative effect of the reversal of the step acquisition is a reduction in petroleum and natural gas properties of $70.4 million (December 31, 2008 – $92.1 million) and a decrease in future tax liability of $20.8 million (December 31, 2008 – $29.1 million).

(F) Bank Loan and Credit Facilities

The weighted average interest rate on short-term borrowings for the year ended December 31, 2009 was 5.66% (December 31, 2008 – 5.39%).

(G) Temporary Equity

The trust units contain a redemption feature which is required for the Trust to retain its mutual fund trust status for Canadian income tax purposes. The redemption feature of the trust units entitles the holder to redeem the Trust Units. However, the restrictions on redemption are not substantive enough to be accounted for as a component of permanent unitholders' equity under U.S. GAAP, in accordance with ASC 480 – "Distinguishing Liabilities from Equity" (formerly, Emerging Issues Task Force ("EITF") D-98 "Classification and Measurement of Redeemable Securities"), the trust units must be presented as temporary equity and recorded on the consolidated balance sheet at their redemption value.

In applying ASC 480, the Trust has recorded temporary equity in the amount of $2,921.6 million as at December 31, 2009 (December 31, 2008 – $1,431.1 million), which represents the estimated redemption value of the trust units and the exchangeable shares (which are convertible into trust units) at the balance sheet date. The difference between the Trust's temporary equity under U.S. GAAP and unitholders' capital under Canadian GAAP is applied to accumulated deficit. The adjustments to accumulated deficit are a debit of $1,302.4 million for December 31, 2009 (December 31, 2008 – credit of $469.6 million).

Under Canadian GAAP, the exchangeable shares of the Trust were presented as a non-controlling interest on the consolidated balance sheet. Net income under Canadian GAAP has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet.

Under U.S. GAAP, the consolidated balance sheet would not include an amount for non-controlling interest and income would not be reduced. Instead, under U.S. GAAP, the estimated redemption amount of the exchangeable shares at the balance sheet date would be included in temporary equity on the consolidated balance sheet.

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2009 and 2008, there were no exchangeable shares outstanding.

(H) Unitholders' Capital

Distributions declared for the year ended December 31, 2009 were $1.56 per unit (December 31, 2008 – $2.64 per unit). The number of trust units outstanding as at December 31, 2009 was 109,298,911 (December 31, 2008 –

97,685,333). Under U.S. GAAP, the number of trust units issued and outstanding is required to be disclosed on the face of the balance sheet.

Costs related to the issuance of trust units for the year ended December 31, 2009 of $5.1 million (December 31, 2008 – $0.2 million) were netted against unitholders' capital. Under U.S. GAAP, in the consolidated statement of cash flows, these amounts would be presented on a gross basis, whereas under Canadian GAAP, they have been netted against the proceeds from the issuance of trust units.

(I) Other Comprehensive Income

ASC 220 – "Comprehensive Income" (formerly, SFAS No. 130 "Comprehensive Income") requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income. Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity effective January 1, 2009, as discussed in the consolidated financial statements under Canadian GAAP. There are no differences between Canadian and U.S. GAAP.

(J) Unit-Based Compensation

The Trust has a Trust Units Rights Incentive Plan as described in note 13. As the exercise price of the unit rights granted under the plan may be subject to downward revisions from time to time, the unit rights plan is a variable compensation plan under U.S. GAAP. Under ASC 718 – "Compensation – Stock Compensation" (formerly, SFAS No. 123R "Share-Based Payments"), the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan, and unlike Canadian GAAP, must allocate the compensation expense between grants issued to operations and general and administrative staff respectively. The fair value of the unit rights has been determined using a binomial-lattice model. Under ASC 718, the Trust's unit-based compensation plan is classified as a liability and the unit rights are fair valued at each reporting date. Compensation expense for the unit rights plan is recognized in income until settlement date based on the reporting date fair value and the portion of the vesting period that has transpired. The accounting for compensation expense for the unit rights plan results in a difference between Canadian and U.S. GAAP, as the Trust classifies the unit rights plan as equity awards and uses the grant date fair value method to account for its unit compensation expense under Canadian GAAP. Under U.S. GAAP compensation expense was increased by $92.6 million for the year ended December 31, 2009 (December 31, 2008 – increased by $1.2 million). The Trust recorded compensation expense of $99.1 million for the year ended December 31, 2009 (December 31, 2008 – $9.0 million) related to the unit rights granted under the Plan. The allocation between operating and general and administrative expenses under U.S. GAAP for the year ended December 31, 2009 was $13.5 million and $85.6 million respectively (December 31, 2008 – $3.0 million and $18.8 million)

The Trust used the binomial-lattice model to calculate the estimated weighted average grant date fair value of $6.38 per unit for unit rights issued during the year ended December 31, 2009 (December 31, 2008 – $2.42 per unit). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2009	2008
Expected annual exercise price reduction (on rights with declining exercise price)	**$1.44 – $2.16**	$2.16 – $3.00
Expected volatility	**39% – 43%**	28% – 39%
Risk-free interest rate	**1.78% – 2.72%**	2.98% – 4.17%
Forfeiture rate	**10%**	10%
Expected life of right (years)[1]	**Various**	Various

(1) *The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Plan.*

The following table is a summary of the status of the unvested unit rights as of December 31, 2009 and 2008 and changes during the years then ended:

	Number of unvested rights	Weighted average grant date fair value
Unvested, December 31, 2007	4,645	$ 3.99
Granted	2,838	$ 2.42
Vested	(2,149)	$ 3.96
Forfeited	(665)	$ 4.12
Unvested, December 31, 2008	4,669	$ 3.03
Granted	1,844	$ 6.38
Vested	(2,227)	$ 3.38
Forfeited	(114)	$ 3.00
Unvested, December 31, 2009	**4,172**	**$ 4.32**

As of December 31, 2009, there was $36.0 million of total unrecognized compensation cost related to unvested unit rights; the cost is expected to be recognized over a weighted average period of 1.4 years. The total fair value of unit rights vested during the year ended December 31, 2009 was $37.0 million (December 31, 2008 – $8.3 million).

The intrinsic value of a unit right is the amount by which the current market value of the underlying trust unit exceeds the exercise price of the unit right.

The following table summarizes information related to unit rights activity during the years ended December 31, 2009 and 2008:

	Number of rights	Weighted average exercise price(1)	Weighted average remaining contract life (years)	Aggregate intrinsic value
Outstanding, December 31, 2008	8,449	$ 14.58	3.3	$ 16,277
Granted	1,844	$ 24.87	4.7	–
Exercised	(2,059)	$ 9.97	1.5	29,468
Forfeited	(114)	$ 16.43	3.2	508
Outstanding, December 31, 2009	**8,120**	**$ 16.68**	**3.1**	**$ 105,720**
Exercisable, December 31, 2009	**3,948**	**$ 13.22**	**2.1**	**$ 65,078**
Expected to vest	**3,755**	**$ 19.96**	**4.0**	**$ 36,578**

(1) Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.

	Number of rights		Weighted average exercise price[1]	Weighted average remaining contract life (years)		Aggregate intrinsic value
Outstanding, December 31, 2007	7,662	$	14.67	3.4	$	35,553
Granted	2,838	$	19.27	4.7		–
Exercised	(1,386)	$	7.69	1.1		23,109
Forfeited	(665)	$	21.79	4.1		1,836
Outstanding, December 31, 2008	8,449	$	14.58	3.3	$	16,277
Exercisable, December 31, 2008	3,780	$	11.52	2.3	$	15,858
Expected to vest	4,201	$	17.07	4.1	$	377

(1) *Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.*

(K) Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate current and future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the Reconciliation of Net Income under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheets – U.S. GAAP include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The implementation of ASC 740 – "Income Taxes" (formerly, FASB Interpretation Number ("FIN") 48) did not result in any adjustment to the beginning tax positions of the Trust. The unrecognized tax benefits of the Trust are disclosed below.

Unrecognized tax benefits, January 1, 2008	$	4,250
Gross decrease for tax positions taken during a prior period		98
Gross decrease for tax positions taken during the current period		(195)
Gross increase for tax positions taken during the current period		447
Reductions due to lapse of applicable statute of limitations		(1,000)
Unrecognized tax benefits, December 31, 2008	$	3,600
Gross increase for tax positions taken during a prior period		61
Gross decrease for tax positions taken during a prior period		–
Gross decrease for tax positions taken during the current period		(566)
Reductions due to lapse of applicable statute of limitations		(175)
Unrecognized tax benefits, December 31, 2009	**$**	**2,920**

All of the Trust's unrecognized tax benefits at December 31, 2009, if recognized, would affect the Trust's effective income tax rate. The Trust does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.

The Trust recognizes interest and penalties related to uncertain tax positions in a component of interest expense. During each of the years ended December 31, 2009 and 2008, interest expense includes $0.3 million of interest related to taxation amounts. There are no accruals of interest and penalties as at December 31, 2009 on the balance sheet (December 31, 2008 – accrued $nil).

Baytex and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax, or the relevant income tax in other international jurisdictions. Baytex may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the

date of mailing of the original notice of assessment in respect of any particular taxation year. For the Canadian federal and provincial income tax matters, the open taxation years range from 2003 to 2009. The U.S. federal statute of limitations for assessment of income tax is generally closed for the taxation years through 2004. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. The tax authorities have not audited any of the income tax returns of Baytex or its subsidiaries for the open taxation years noted above.

(L) Petroleum and Natural Gas Revenues

Under U.S. GAAP, petroleum and natural gas revenues are required to be presented net of royalties, excise and sales taxes to governments and other mineral interest owners.

(M) Interest

Under U.S. GAAP, interest income should be disclosed separately from interest expense on the face of the income statement. For the year ended December 31, 2009, interest income netted against the interest expense was $0.1 million (December 31, 2008 – $0.2 million).

(N) Business Combinations

Under ASC 805 – "Business Combinations" (formerly, SFAS 141, "Business Combinations"), supplemental pro forma disclosure is required for significant business combinations occurring during the year. On June 4, 2008 the Trust completed a business combination that was deemed a significant acquisition. The following unaudited pro forma information provides an indication of what the Trust's results of operations might have been under U.S. GAAP had the business combination taken place on January 1, 2008:

(unaudited)	2008 Pro Forma
Petroleum and natural gas sales	$ 1,196,599
Net (loss)	$ (281,457)
Net (loss) per trust unit:	
Basic	$ (2.96)
Diluted	$ (2.96)

(O) Earnings Per Share

Under Canadian GAAP, basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged and convertible debentures were converted. Under U.S. GAAP, since the exchangeable shares are classified in the same manner as the trust units, basic net income per unit is calculated based on net income divided by weighted average units and the unit equivalent of the outstanding exchangeable shares.

(P) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

(Q) Additional Disclosures

1. The components of accounts receivable are as follows:

As at December 31	2009	2008
Petroleum and natural gas sales and accrual	$ 107,657	$ 62,926
Joint venture	28,581	23,755
Prepaid, deposits and other	3,252	3,280
Less: allowance for doubtful accounts	(2,336)	(2,410)
	$ 137,154	$ 87,551

2. The components of inventory are as follows:

As at December 31	2009	2008
Petroleum and condensates	$ 1,217	$ 72
Other	167	260
	$ 1,384	$ 332

3. The components of accounts payable and accrued liabilities are as follows:

As at December 31	2009	2008
Trade payables	$ 81,387	$ 64,067
Joint venture	23,564	25,670
Petroleum and natural gas accrued liabilities	63,500	66,361
Other	12,042	8,255
	$ 180,493	$ 164,353

(R) Commitments and Contingencies

For the year ended December 31, 2009, the Trust recorded an expense for operating leases of $2.9 million (December 31, 2008 – $2.8 million). The operating leases have expiration dates ranging from April 2010 to April 2020.

(S) Supplemental Information

Change in Non-Cash Working Capital Items

For the years ended December 31	2009	2008
Operating activities		
Accounts receivable	$ (39,565)	$ 29,795
Crude oil inventory	(1,052)	5,665
Accounts payable and accrued liabilities	12,689	3,397
Foreign exchange on working capital	50	–
	(27,878)	38,857
Investing activities		
Accounts receivable	(10,038)	–
Accounts payable and accrued liabilities	3,451	19,874
	(6,587)	19,874
	$ (34,465)	$ 58,731

(T) Recent Developments in U.S. Accounting

In August 2009, the FASB issued Accounting Standards Update ("ASU") 2009-05 – "Fair Value Measurements and Disclosures (Topic 820) – Measuring Liabilities at Fair Value" ("ASU 09-05"), which became effective the first reporting period (including interim periods) beginning after issuance. ASU 09-05 requires entities to measure the fair value of liabilities using one or more of several prescribed valuation techniques within the ASU when quoted prices in an active market for the identical liability are not available. The ASU also clarifies that: entities are not required to include separate inputs or adjustments to other inputs relating to the existence of restrictions that prevent the transfer of liabilities when estimating their fair value; and quoted prices in active markets for identical liabilities at the measurement date and the quoted prices for identical liabilities traded as assets in active markets when adjustments to the quoted prices of assets are required are Level 1 fair value measurements. The adoption of this standard did not have a material impact on the Trust's financial statements.

In June 2009, the FASB issued ASU 2009-01 ("ASU 09-01") "Topic 105 – Generally Accepted Accounting Principles" (formerly, SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles"). This standard became effective for interim and annual periods ending after September 15, 2009. The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. GAAP. The adoption of this standard did not have a material impact on the consolidated financial statements of the Trust.

In May 2009, the FASB issued ASC 855 "Subsequent Events" (formerly, SFAS No. 165, "Subsequent Events"), which establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. The guidance was effective for interim or annual periods ending after June 15, 2009. The adoption of this guidance did not have a material impact on the consolidated financial statements of the Trust.

In March 2009, the FASB issued ASC 815 "Derivatives and Hedging" (formerly, SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities") effective January 1, 2009. The standard requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts and details of credit-risk-related contingent features in those derivative contracts. The standard also requires disclosure of the financial statement location and amounts of derivative instruments in the applicable financial statement for each interim and annual reporting period. The disclosures required by this new standard are located in note 18 and did not have a material impact on our results of operations or financial position.

In January 2009, the FASB issued ASC 805 "Business Combinations" (formerly, SFAS 141(R), "Business Combinations", which replaced SFAS 141), which requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard may have an impact on the Trust's U.S. GAAP accounting for future business combinations.

In January 2009, the FASB issued ASC 810 "Consolidation" (formerly, SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51"), which requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP Consolidated Statement of Earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the non-controlling interest and to disclose these respective amounts. The adoption of this standard did not have a material impact on the consolidated financial statements of the Trust.

In December 2008, the SEC released Final Rule Release No. 33-8995 "Modernization of Oil and Gas Reporting," subsequently updated with ASU 2010-03 – "Oil and Gas Reserve Estimation and Disclosure" to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to

lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report petroleum and natural gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The ruling is effective for disclosures in our Annual Report on Form 40-F for the year ended December 31, 2009. Adoption of the new standard is reflected in the results of future ceiling tests for the Trust.

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
AcSB	Accounting Standards Board
bbl	barrel
bbl/d	barrel per day
bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
Capex	capital expenditures
CICA	Canadian Institute of Chartered Accountants
E&D	exploration and development
E&E	exploration and evaluation
FD&A	finding, development and acquisition costs
F&D	finding and development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLB	Lloyd Light Blend
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
*mmboe**	million barrels of oil equivalent
mmBtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PP&E	property, plant and equipment
RLI	reserve life index
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Executive Chairman
Baytex Energy Ltd.

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

Edward Chwyl (2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Anthony W. Marino
President & Chief Executive Officer
Baytex Energy Ltd.

Gregory K. Melchin (1)
Independent Businessman

Dale O. Shwed (3)
President & Chief Executive Officer
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

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AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
Bank of Nova Scotia
BNP Paribas (Canada)
Canadian Imperial Bank of Commerce
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

OFFICERS

Raymond T. Chan
Executive Chairman

Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Exploration

Murray J. Desrosiers
Vice President,
General Counsel and Corporate Secretary

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, U.S. Business Development

R. Shaun Paterson
Vice President, Marketing

Richard P. Ramsay
Vice President, Heavy Oil

Mark F. Smith
Vice President, Conventional Oil & Gas

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

BAYTEX

ENERGY TRUST

www.baytex.ab.ca